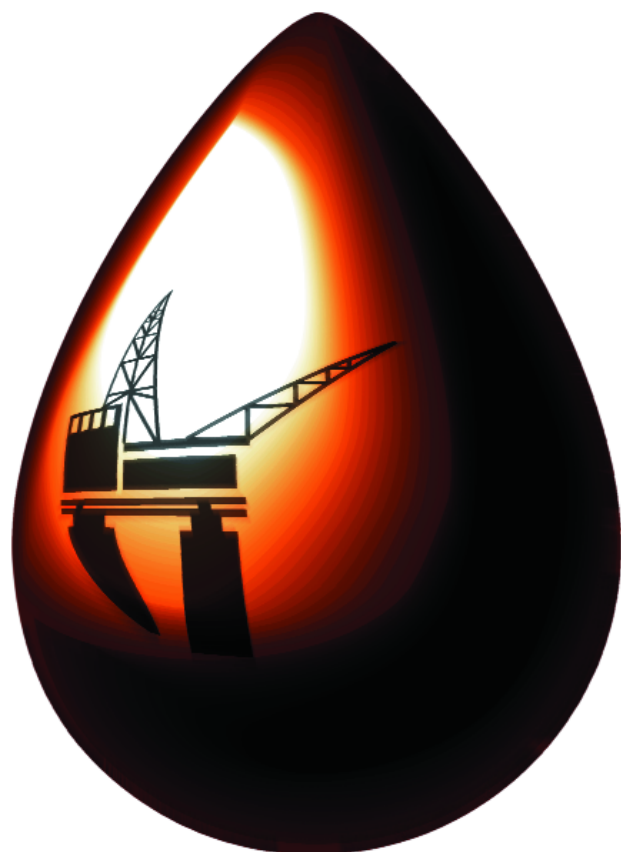




Introduction to the Oil Industry

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UBS Global Oil and Gas Team

The UBS Global Oil and Gas team comprises 20 analysts and four global sector specialist sales people in 12 locations around the world, covering 115 stocks with a combined market capitalisation of \$1.9 trillion.

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Source: UBS

Oil and gas publications

In addition to our stock-specific and ad hoc industry reviews, we publish a broad range of regular reports on each subsector: integrated oils, oilfield services, exploration and production, and global emerging markets. Our regular publications are detailed below. If you would like to receive any of these please advise your usual UBS contact or e-mail ubs.global-oil@ubs.com.

You may also access our research electronically at www.ubs.com/research/oilgas where you will find summary models for all of our stocks.

Daily Oil News – two-page round-up of major commodity and share price movements, company and industry news, together with a summary of all UBS oil and gas publications from the previous 24 hours.

Global Integrated Oil Analyser – published twice a year and including summary P&L, cash flow and balance sheet data for each of the 30 listed integrated oil companies around the world, together with detailed operating and financial comparisons and forecasts.

Global Valuation and Performance Data and Sector Diary – weekly overview of stock movements, valuation and performance comparisons by subsector and a global sector diary listing forthcoming results, etc.

OECD inventory report – monthly analysis of OECD oil stock data.

CFTC report – weekly report analysing the open interest data published by the Commodity and Futures Trading Commission.

DOE report – weekly report analysing the US crude and product stock data published by the Department of Energy.

EIA report – weekly review of the EIA gas storage data.

Global Energy Indices – developed in conjunction with Thomson Financial Datastream, encompassing all larger quoted stocks in each region and subsector.

US and International Refining Margins – weekly report.

Oil Service Bits – weekly comparative statistics and news and views from the oilfield services industry.

North American E&P Weekly – comparative statistics and news and views on the US and Canadian E&P sectors.

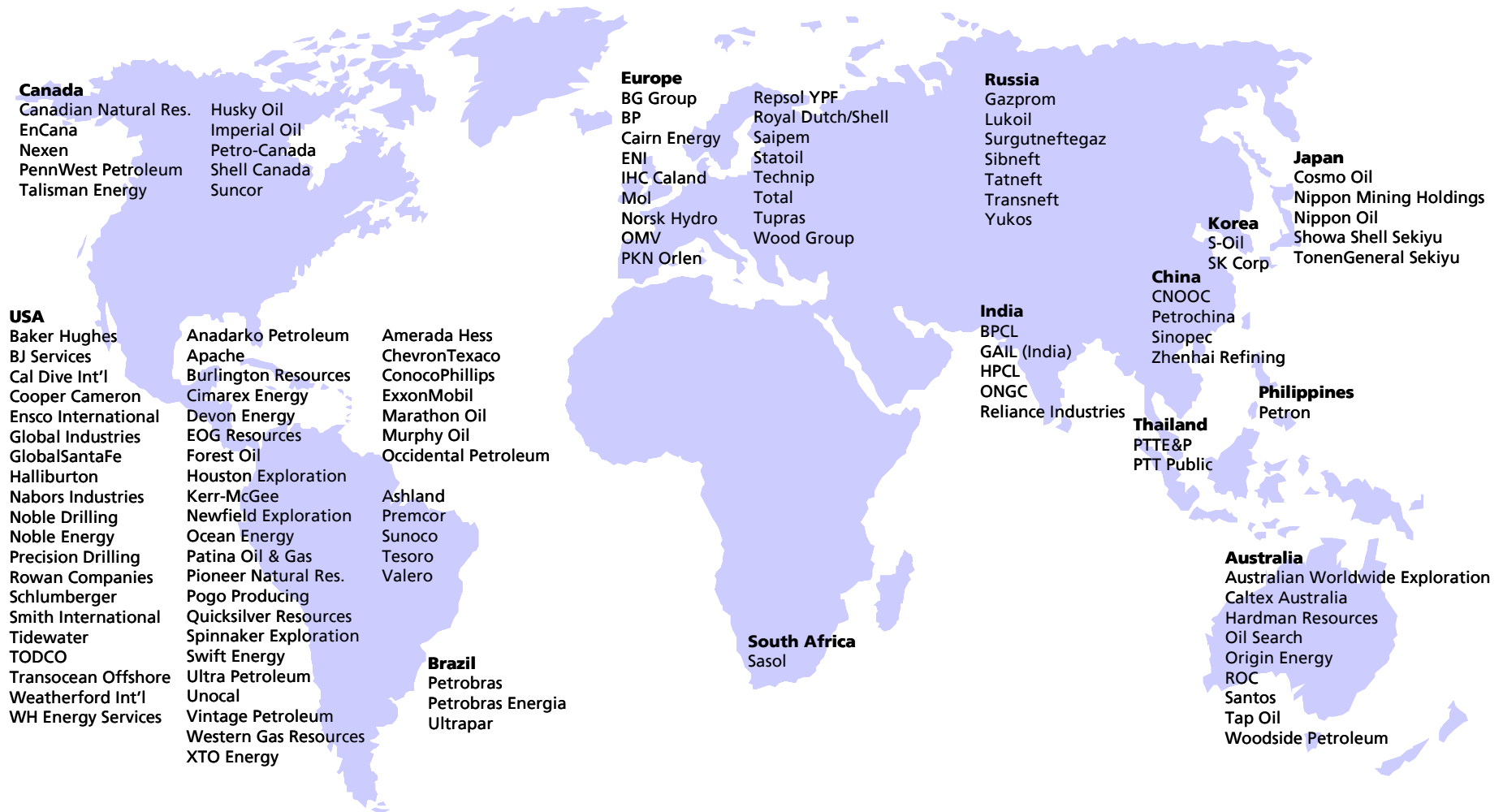
GEM Oil and Gas Strategy – bi-monthly strategy document outlining our views and ratings on the 20 most important emerging-market oil stocks, together with a recommended model portfolio.

Patchwork Survey – proprietary survey of oil company operating personnel regarding near-term expectations and trends for oilfield activity and service/product activity.

US E&P Accounting Survey – annual survey of US E&P company accounting practices.

Country Briefings – periodic reviews of the oil and gas industry of a specific country.

UBS global oil coverage



Source: UBS

What are hydrocarbons?

‘Hydrocarbon’ is the term used to describe any organic compound consisting only of carbon and hydrogen. Hydrocarbon reserves evolve naturally and are derived from the decomposition of organic matter, algae and bacteria trapped and preserved in sedimentary deposits. Burial of these deposits and the corresponding increase in heat and pressure ‘cooks’ the organic matter. This breaks down the complex hydrogen and carbon molecules and converts them into solid, liquid or gaseous hydrocarbons known as fossil fuels.

Coal is generally formed from the remains of land-based plants. Oil is typically derived from marine (water-based) plants and animals (mainly algae). Natural gas can be formed from almost any marine or terrestrial organic material.

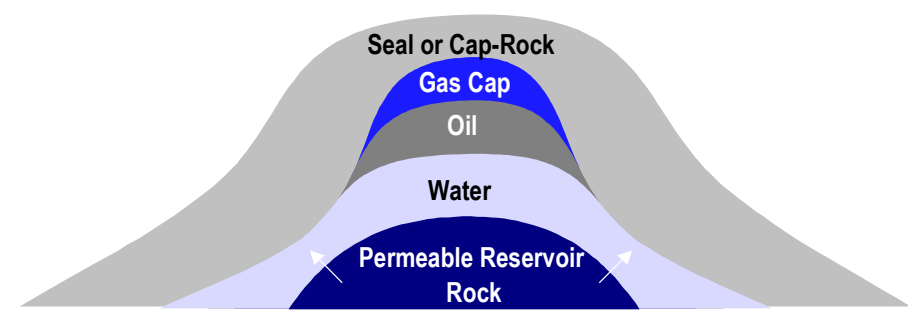
Rocks containing a percentage of organic matter sufficiently high to form oil and gas in this manner are known as **source rocks**. However, due to the force of gravity (hydrocarbons are less dense than the surrounding rock) and the pressure created by the overlying rock layer, oil and gas seldom stay in the source rock in which they are formed. Instead they move through to underground layers of sedimentary rocks until they either escape at the surface or are trapped by a barrier of less permeable rock to form oil and gas fields.

Oil and gas fields form in permeable **reservoir rocks**, usually sandstone or chalk, where the migrating hydrocarbons are trapped by an impermeable layer of rock known as the **cap or seal**. Hydrocarbons only accumulate where the seal and reservoir rocks are in the right shape and relative position to form **traps**. The two main types of trap are **structural** traps formed by earth movements, which fold the rock into suitable shapes, and **stratigraphic** traps, where a suitable combination of rock types is deposited in a particular environment.

A trap requires three elements:

- A porous reservoir rock to accumulate the oil and gas – typically sandstones, limestone and dolomites
- An overlying impermeable rock to prevent the oil and gas from escaping
- A source for the oil and gas, typically black waxy shales.

Figure 1: Trap



Source: UK offshore operators' association

Hydrocarbon reserves are derived from the decomposition of organic matter

Oil and gas fields form in permeable reservoir rocks

All hydrocarbon fields form by the chance occurrence of the deposition and maturation of a source rock, migration into a reservoir rock and entrapment in a structure beneath an impermeable seal.

Crude oil

Crude oil is not a homogeneous material. Its physical appearance varies from a light, almost colourless liquid to a heavy viscous black/brown sludge.

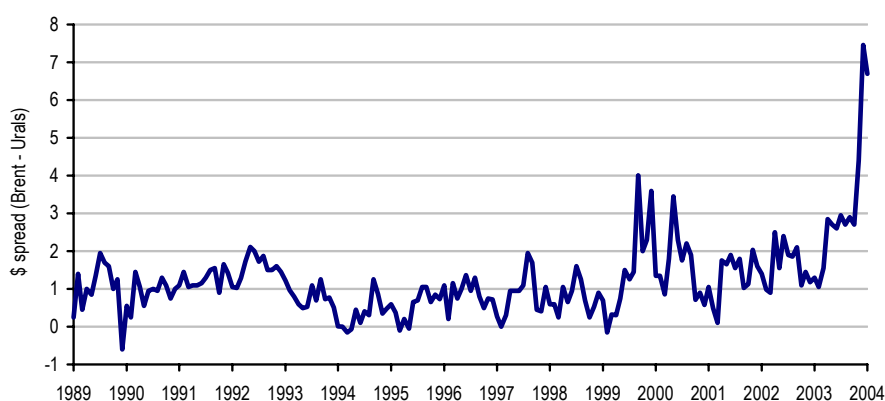
Crude oil is not a homogeneous material...

During the formation of hydrocarbons, the hotter the **source rock**, the further the hydrocarbon chain breaks down and the lighter the oil. Density (light/medium/heavy) is classified by the American Petroleum Institute (API). **API gravity** is defined in terms of density at 20 degrees centigrade. The higher the API, the lighter the crude. **Light** crudes generally exceed 38 degrees API and **heavy** crudes are generally those with an API gravity of 22 degrees or less. Crude oil is also classified by **sulphur content**. **Sweet** crude has less than 1% sulphur content, **sour** crudes greater than 1%. Crude prices vary depending on the oil's density, sulphur content, and other physical characteristics, as well as its proximity to markets.

...it is classified according to weight and sulphur content

The graph below illustrates this price differential, plotting the spread between a light sweet crude (in this case Brent) and a heavy benchmark (Urals). Over the past 15 years Brent has traded at a \$1.20 per barrel premium to Urals, essentially reflecting the additional refining required for the heavier crudes to produce the lighter products demanded by the market. The spread is also governed by the demand for end products. Heavier crudes tend to produce a greater proportion of 'heavier' products such as fuel oil, for which demand (and hence prices) have been weak recently. As demand for oil products has risen, and production with it, so the average grade of crude oil has deteriorated, leaving the world with a shortage of the more sophisticated refining capacity required to process the heavier crudes.

Chart 1: Brent / Urals spread



Source: Thomson Financial Datastream

For pricing purposes, crude oils of similar quality are often compared to a single representative crude oil, a ‘benchmark’ of the quality class. The quality of the crude oil dictates the level of processing and re-processing necessary to achieve the optimal mix of product output. Hence, price and price differentials between crude oils also reflect the relative ease of refining. A premium crude oil like West Texas Intermediate, the US benchmark, has a relatively high natural yield of desirable naphtha and straight-run gasoline. Another premium crude oil, Nigeria’s Bonny Light, has a high natural yield of middle distillates. By contrast, almost half of the simple distillation yield from Saudi Arabia’s Arabian Light, the historical benchmark crude, is a heavy residue (‘residuum’) that must be reprocessed or sold at a discount to crude oil. Even West Texas Intermediate and Bonny Light have a yield of about one-third residuum after the simple distillation process.

In addition to gravity and sulphur content, the type of hydrocarbon molecules and other natural characteristics may affect the cost of processing or restrict a crude oil’s suitability for specific uses. The presence of heavy metals, contaminants for processing and for the finished product, is one example. The molecular structure of a crude oil also dictates whether a crude stream can be used for the manufacture of specialty products, such as lubricating oils, or of petrochemical feedstocks.

Refiners therefore strive to run the optimal mix (or ‘slate’) of crudes through their refineries, depending on the refinery’s equipment, the desired output mix, and the relative price of available crudes. In recent years, refiners have confronted two opposite forces – consumers’ and government mandates that increasingly require light products of higher quality (the most difficult to produce) and crude oil supply that was increasingly heavier, with higher sulphur content (the most difficult to refine).

Natural gas

Natural gas is a mixture of light hydrocarbons, predominantly methane. Around three-quarters of the world’s natural gas is found in separate accumulations from crude oil (‘**non-associated gas**’); the remainder is found in combination with or in solution in crude oil (‘**associated gas**’).

Natural gas is a mixture of light hydrocarbons

The constituent elements of natural gas vary throughout the world and typically include (in varying proportions) methane and ethane, plus propane, butane and heavier compounds, which are collectively known as natural gas liquids (**NGLs**). Natural gas often contains inert substances such as sulphur, carbon dioxide and nitrogen, which lower its thermal efficiency and hence its value, unless removed.

Natural gas is also often discovered associated with significant volumes of **condensate**, a light oil which is gaseous under reservoir conditions and usually enhances the value of the discovery. These reservoirs are called gas/condensate fields. They are also normally deep and high pressure, which makes them costly to develop. In contrast to oil fields, where the gas content is measured by the GOR (gas-oil ratio), the condensate content in these fields is measured by the CGR (condensate-gas ratio).

The significance of natural gas within the energy mix is increasing at the expense of oil and coal as consumers look to take advantage of its environmental characteristics, including lower sulphur dioxide (SO₂) and nitrogen oxide (NO_x) emissions.

Natural gas does not have an internationally recognised benchmark price such as Brent or WTI for crude oil. Prices have typically been set in relation to competing fuels such as crude, fuel oil and gas oil. The contractual terms are generally highly confidential. However, as markets have liberalised, benchmark pricing has emerged, most notably the **Henry Hub** index in the US, the **Alberta** index in Canada and the **IPE** natural gas contract in the UK.

Natural gas liquids

Natural gas liquids (NGLs) comprise heavier hydrocarbon fractions, which are extracted in liquid form from natural gas, usually at or near the point of gas production, or in a separate processing or treatment plant. NGLs can be further classified as **ethane**, **liquefied petroleum gas (LPG)** – mainly propane and butane – and **condensate** (natural gasoline), the latter being in liquid form.

Natural gas liquid margins are influenced by two factors: natural gas prices and crude oil prices. Natural gas is the feedstock for NGLs. Wet natural gas is piped into a natural gas processing plant where impurities are stripped out, resulting in dry natural gas. These impurities, which include propane, ethane and butane, are packaged and sold as NGLs.

NGLs serve as feedstocks in the petrochemical industry or as blending agents in the refinery industry. NGLs, which are sold in barrel units, sell, on average, at 70% of the price of WTI crude. Thus, if crude prices are rising, NGL prices will typically rise as well.

There is no comparable worldwide benchmark price for natural gas as gas tends to be a regional business

Natural gas liquids are extracted in liquid form from natural gas

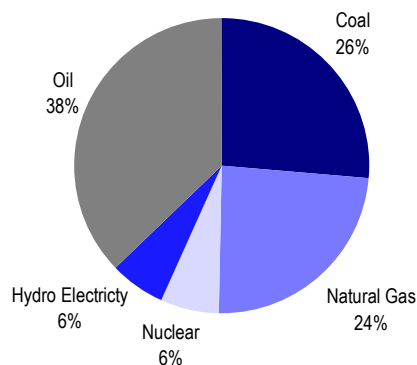
NGLs serve as feedstocks in the petrochemical industry or as blending agents in the refinery

World oil markets

Oil continues to be the world's most important source of energy. It met 38% of global energy needs in 2003 while its nearest rivals, coal and natural gas, met only 26% and 24% respectively. Oil's share is even higher than this in most regions. The exceptions are Asia-Pacific, where coal (44% of consumption) is the leading energy source, and the former Soviet Union (FSU), where it is gas (54%).

Oil continues to be the world's most important source of energy

Chart 2: World energy consumption by fuel 2003 (excluding alternate power sources)



Source: BP Statistical Review

Where is it?

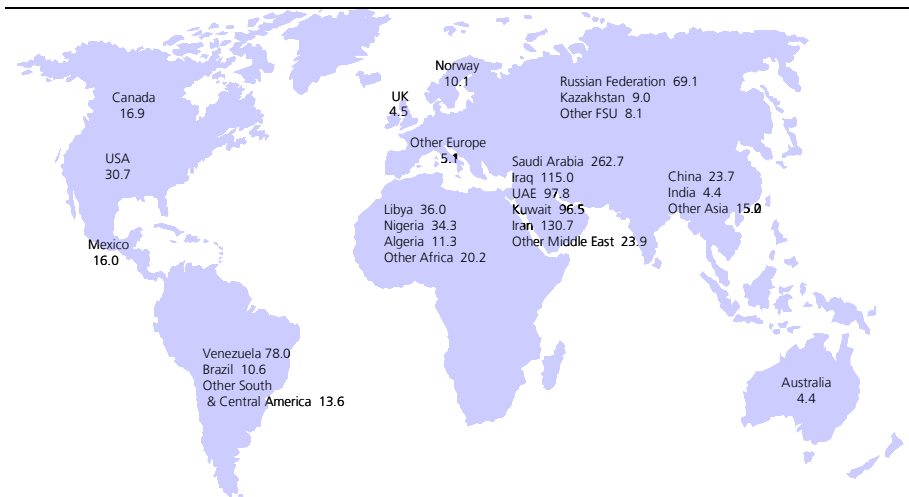
The Middle East dominates proven reserves of oil, specifically oil that has been discovered and is considered economic to produce at today's prices, cost structure and technology. The Middle East currently has almost two-thirds of the 1.15 trillion barrels of the world's proven reserves (BP Statistical Review), which is why the region has disproportionate geopolitical importance.

The Middle East dominates proven reserves

The distribution of proven reserves is only a rough approximation of how oil is distributed around the world. For example, the deep waters of the Gulf of Mexico and offshore West Africa have only been added to the proven reserves list relatively recently, as technology to develop their oil has become available. In addition, countries that are open to private industry tend to be under-represented, because commercial incentives encourage companies to hold only as many reserves as they can develop and bring to market within a reasonable timeframe.

The distribution of proven reserves is only a rough approximation of how oil is distributed around the world

Political incentives, meanwhile, encourage producing countries to maximise reported reserves. Thus, most Middle East countries have reserves/production (R/P) ratios of around 90 years, while the US R/P ratio is only 11.3 years. This does not mean the US will run out of oil in 11 years; the US R/P ratio has been around 10 or 11 years for decades. It means more oil has to be proved up.

Chart 3: Distribution of proved oil reserves, end-2003 (billion barrels)

Source: BP Statistical Review

Who produces it?

There are three producing countries in the world that stand head and shoulders above all others: Saudi Arabia (9.8 million barrels/day (mb/d) in 2003), Russia (8.5) and the US (7.5). Between them, they produce over a third of the world's crude oil, condensate and natural gas liquids. The rest of the world's production is widely dispersed among more than 60 countries, none of which accounts for more than 5% of the total.

Regionally, the Middle East dominates supply, with 29% of the total. Indeed, when Iraq is fully reintegrated into the international oil market the region's significance may grow still further.

The clear number two producing region is North America, thanks mainly to the US. All the other producing regions (Africa, South America, North Sea, Far East) are broadly similar, with each accounting for 9-10% of the total.

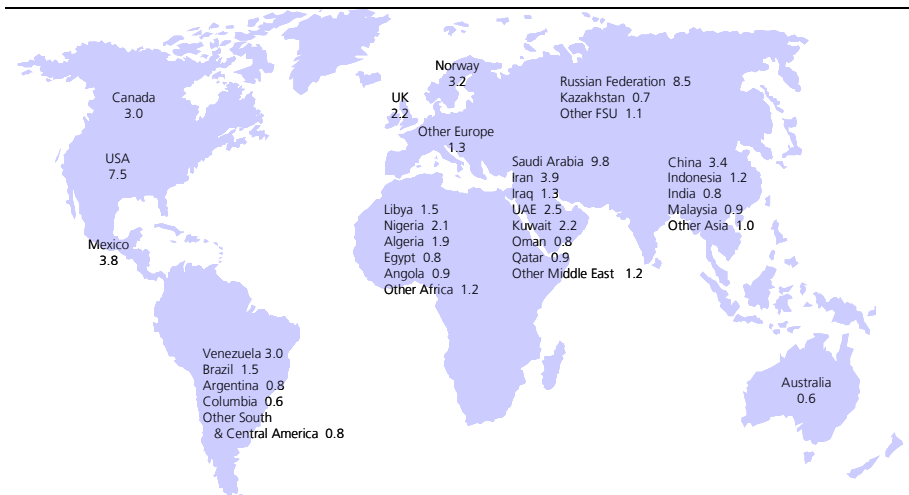
Governments around the world own and control the majority of oil resources. The greatest exception is the US, where private landowners play an important role, and receive the royalty payments that flow to governments elsewhere.

There are three producing countries in the world that stand head and shoulders above all others

Regionally, the Middle East dominates supply

The clear number two producing region is North America

Governments control the majority of oil resources

Chart 4: Global oil production, 2003 (million barrels per day)

Source: BP Statistical Review

World oil supply trends

Global trends

World oil production has been on a rollercoaster ride similar to demand for the last 30 years. However, the timing of the peaks and troughs has not always matched. For example in 1999, world demand continued to grow, but high inventories built up during 1997-98, when production got too far ahead of demand, forced producers to cut back below 1998 levels. More recently, demand has outstretched supply as China has experienced rapid, energy-intensive, economic development at a time of heightened geopolitical tensions in the Middle East which has sent oil consistently above \$50 a barrel.

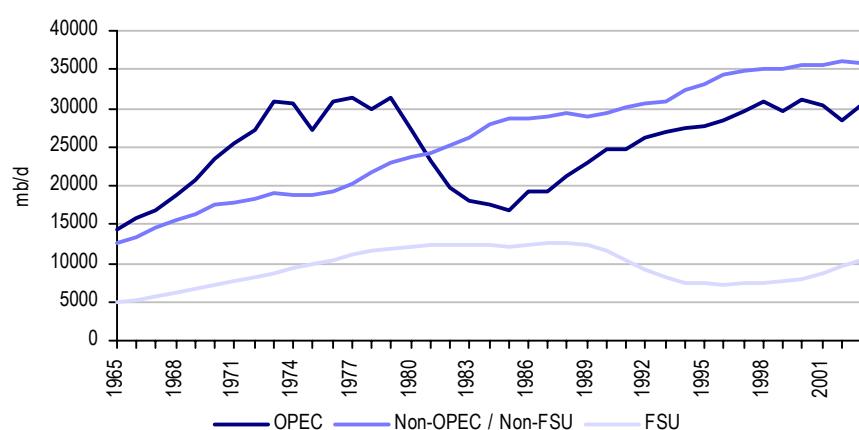
World production has frequently risen when prices are falling, and vice versa. A prime example of this occurred during the second half of the 1980s, when production grew, even though prices had been roughly halved by the third oil price shock, in 1986. This apparent departure from the normal rules of economics reflects the long lead times involved in exploring for and developing oil, the high capital/low operating cost bias of most upstream projects, and the presence of a cartel: OPEC, the Organization of Petroleum Exporting Countries.

World production has frequently risen when prices are falling, and vice versa

OPEC

The **Organization of Petroleum Exporting Countries (OPEC)** was founded in 1960 in response to rising global production. However, it was not until 1973, after the Arab-Israeli war and the Arab oil embargo, that OPEC members took over control of their production, prices and sales from the oil companies and started operating as a cartel, co-ordinating first prices and then volumes. **Quotas were first introduced in 1982.** Today, OPEC member countries supply around 39% of the world's oil and possess 77% of the world's total proven crude oil reserves. The graph below illustrates how OPEC's production has fluctuated in relation to the world's other major suppliers.

OPEC was founded in 1960

Chart 5: Global oil supply

Source: BP Statistical Review

The founder members of OPEC were Saudi Arabia, Kuwait, Iran, Iraq and Venezuela. By 1975 the membership had grown to 13, with the inclusion of Qatar (in 1961), Indonesia (1962), Libya (1962), UAE (1967), Algeria (1969), Nigeria (1971), Ecuador (1973-1992) and Gabon (1975-1994).

OPEC says its principal aims are “The co-ordination and unification of petroleum policies of Member Countries and the determination of the best means for safeguarding their interests, individually and collectively. The Organization also seeks to devise ways and means of ensuring the stabilisation of prices in international oil markets with a view to eliminating harmful and unnecessary fluctuations, due regard being given at all times to the interests of the producing nations and to the necessity of securing a steady income for them; an efficient, economic and regular supply of petroleum to consuming nations; and a fair return on their capital to those investing in the petroleum industry.”

The current membership and respective quotas are shown below:

Table 1: OPEC quotas (from November 2004)

	(million barrels/day)
Saudi Arabia	8.78
Iran	3.96
Venezuela	3.11
UAE	2.36
Nigeria	2.22
Kuwait	2.17
Libya	1.45
Indonesia	1.40
Algeria	0.86
Qatar	0.70
Total (excluding Iraq)	27.00
Iraq	Current production rate 2.3 mb/d No current quota

Source: OPEC

OPEC meets half yearly, usually in June and November, although there is flexibility to call ad hoc meetings.

In September 2004 the OPEC-10, already producing at 25-year high volumes, agreed to increase official production quotas by a further 1 million barrels a day to 27 million barrels with effect from the following November. However, due to concerns over inventory shortages and potential supply disruptions, particularly in Iraq, these OPEC nations consistently broke their production restrictions, supplying over 30 million barrels of oil a day.

OPEC's production has varied much more than global production, because of its cartel actions. Thus, when OPEC tried to maintain prices in the first half of the 1980s, despite rising non-OPEC supply and slumping demand, its crude oil production collapsed from 30 mb/d to 16 mb/d and its market share fell from 48% to 30%. These subsequently recovered to 28 mb/d and 43% in early 1998, only to be squeezed again as OPEC tried to deal with the surplus that triggered the 1998 price crash and the fall in demand triggered by economic slowdown in 2001. Today, OPEC's market share, including Natural Gas Liquids, is around 39%.

OPEC's production has varied more than global production

The greatest swinger of all has been Saudi Arabia, the world's largest oil producer, exporter and owner of reserves and, for a period, OPEC's self-appointed swing producer. It has seen its production collapse from nearly 10 mb/d in 1980 to barely over 2 mb/d in late 1985, and back up to 9.8 mb/d currently.

The greatest swinger of all has been Saudi Arabia

Such frenzied swings have been absent from the non-OPEC production profile, which has been generally either flat or rising over the last three decades, thanks to some counterbalancing regional trends.

Regional trends

Two of the world's top three producing areas – the FSU and North America – have seen their production decline, while the rest of non-OPEC has enjoyed a period of increasingly rapid growth.

Two of the top three producing areas have seen their production decline

As the FSU abandoned the guiding principles of communism but failed to make the full transition to capitalism, it suffered an unprecedented collapse in production. It dropped by 45% from its 1987-88 peak of 12.6 mb/d in just 10 years, before starting to stabilise and edge upward in the mid-to-late 1990s. Indeed, this recovery has strengthened recently, with FSU production up a further 28% between 2000 and 2003 to 10.3 mb/d.

The FSU suffered an unprecedented collapse, but is growing strongly again now

US oil production peaked at 11.3 mb/d in the early 1970s, and has been declining since, despite temporary relief provided first by the 1977 start-up of Alaskan North Slope production and, recently, by the deepwater Gulf of Mexico. With production rapidly approaching 2 mb/d, the latter is poised to become the top US oil-producing region. But it will not be enough to enable the US to buck the downward trend that comes from it being the most mature, most explored, and most drilled country in the world. An average US well produces just 11 barrels/day versus over 30,000 barrels/day for a Saudi Arabian well.

US oil production peaked in the early 1970s

Middle East production follows broadly the same path as OPEC production, since six of the cartel's 11 members, and all except one of its largest producers, are in both OPEC and the Middle East. Arguably, Middle East production would have been higher over much of the last two decades if Iraqi production had followed a more normal path. Instead, its production has been dramatically curtailed several times, first by the Iran-Iraq war, then by the UN embargo imposed after Iraq's invasion of Kuwait, and finally by terrorist disruptions to pipelines in the aftermath of the second Iraq war. Consequently, Iraqi production is currently running at about 2.3 mb/d, which is still significantly below its 3.5 mb/d annual peak in 1979 and capacity which is thought to be around 3 mb/d.

Middle East production was curtailed by the Iran-Iraq war and the UN embargo

North Sea production has proceeded in a series of growth spurts and plateaus that reflect the changing competitiveness of its costs. It led the early-1990s initiatives on cost-cutting, restructuring and the use of new technology; however, it would appear that North Sea production reached its peak of 6.4mb/d in 2000 and has since been in decline, with current production at only 5.8mb/d and continuing to fall. Norway, the second-largest of the five North Sea producers, is the world's third-largest exporter, after Saudi Arabia and Russia, and sometimes co-operates with OPEC in controlling production.

North Sea production looks to be in decline

The Caspian, one of the world's oldest producing regions, is also one of the hot new ones because of its large reserves and because the region has strategic and geopolitical importance for both the US and Russia. However, development has been slow and it will likely be several years before the Caspian takes its place on the list of top oil-exporting regions.

Caspian development is proving painfully slow

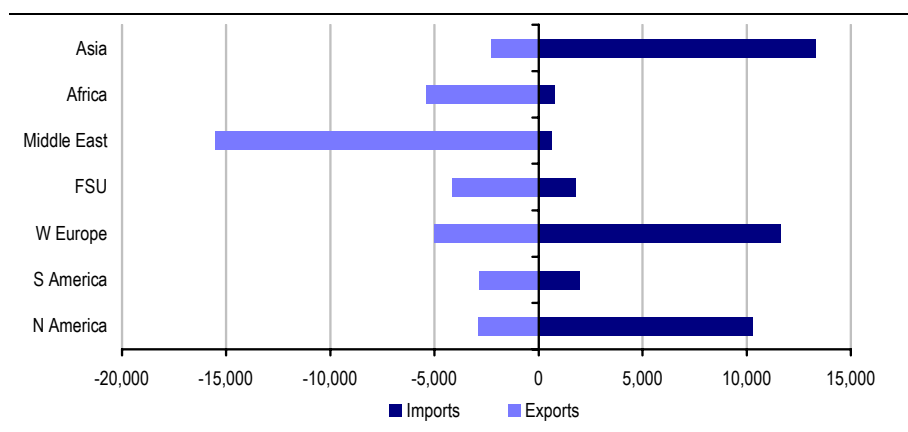
Who supplies whom?

The oil trade is the world's largest, whether measured by value, volume, or ton-miles. Indeed, in 2001 just under 15 billion barrels of oil were traded across international borders, which at today's prices represents trade flows worth well over \$700 billion a year.

The oil trade is the world's largest

As the regional supply and demand patterns are quite different, inter-regional trade (that is, imports and exports) plays an important role in the world oil market. The three large consuming regions – North America, Europe and Asia-Pacific – are all net importers. All the other regions are net exporters.

The three large consuming regions – North America, Europe and Asia-Pacific – are all net importers

Chart 6: Regional imports and exports ('000 bpd)

Source: EIA

The US is the largest single importer, both net and gross. However, because Canada and Mexico are two of the US' three top suppliers, it is not North America but Asia-Pacific that is the largest regional importer. On the export side, the clear winner is the Middle East.

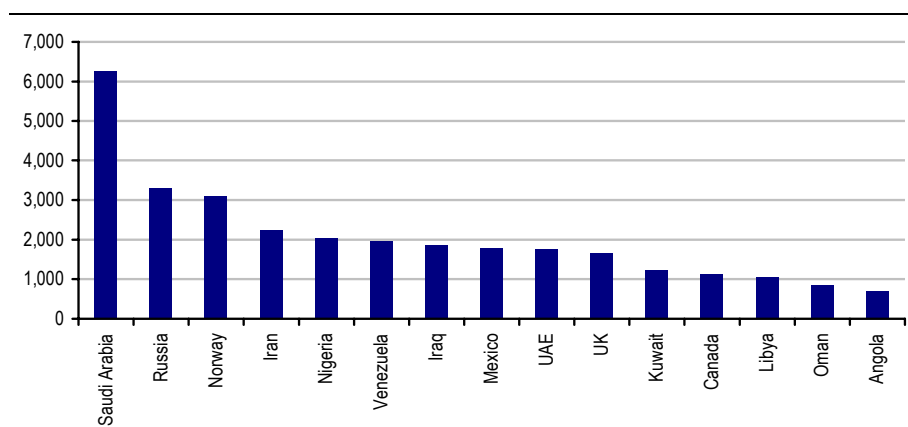
The US is the largest single importer

Crude and products flow to the nearest markets first, if everything else is equal, because they will have the lowest transportation cost and will therefore give the supplier the highest net revenue. However, differences in other factors such as import tariffs, fees, import/export bans, maximum usable ship size, refinery configurations etc., mean that the 'nearest first' rule doesn't always apply.

Crude and products flow to the nearest markets first

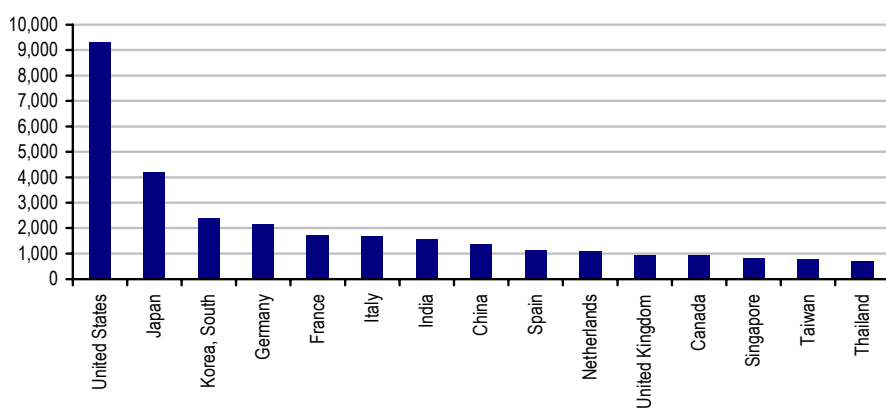
World trade flows are heavily biased toward crude oil because, as the economics favour siting refineries close to consumers rather than close to the wellhead, it is crude primarily that is shipped long distances.

The graphs below illustrate the 15 largest oil importers and exporters. These graphs clearly show how dependent the west (particularly the US) currently is on Middle Eastern oil and the need to diversify supply sources to reduce exposure to a single region.

Chart 7: World's largest exporters 2003 ('000 bpd)

Source: BP Statistical Review

Chart 8: World's largest importers 2003 ('000bpd)



Source: BP Statistical Review

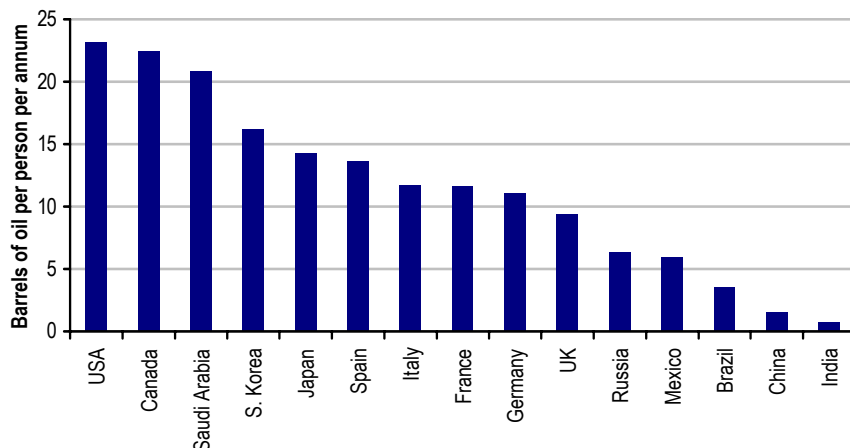
World oil demand trends

Who uses it?

The one major similarity between the distributions of oil supply and of oil demand is the importance of the US. **The US is easily the largest single consumer of oil**, using 20.1 mb/d in 2003, just over 25% of total global demand and over three times the amount consumed by its nearest rivals, specifically China consuming 6.0mb/d and Japan, 5.5mb/d.

The US is easily the largest single consumer of oil

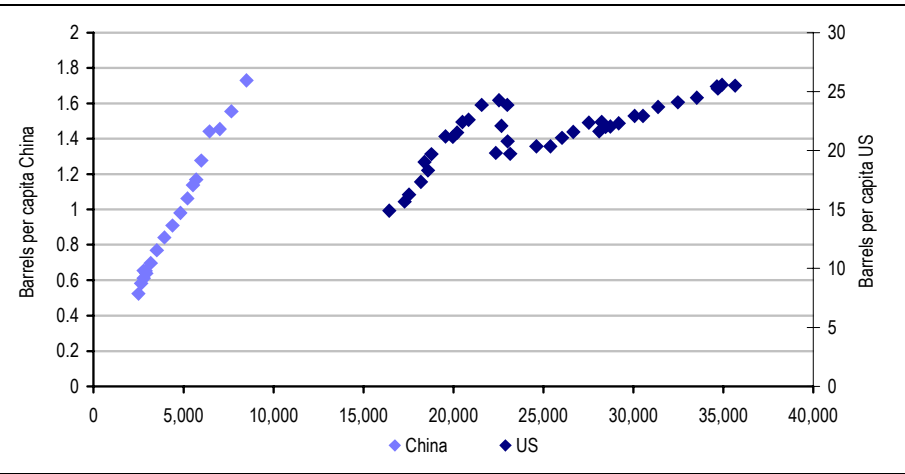
Chart 9: Oil consumption per capita in barrels (2003)



Source: Thomson Financial Datastream

As the graph above shows, however, China's high consumption is due largely to the size of its population. Its consumption per capita, although growing rapidly, remains low at under two barrels per person per year. North America, however, with annual average consumption per capita of almost 25 barrels, reflects the positive correlation between economic maturity, a high standard of living and oil use. This is further borne out in the graph below, showing per-capita oil usage and GDP growth for China and the US. This suggests that the continued growth of the Chinese economy will stretch world oil supplies for the foreseeable future.

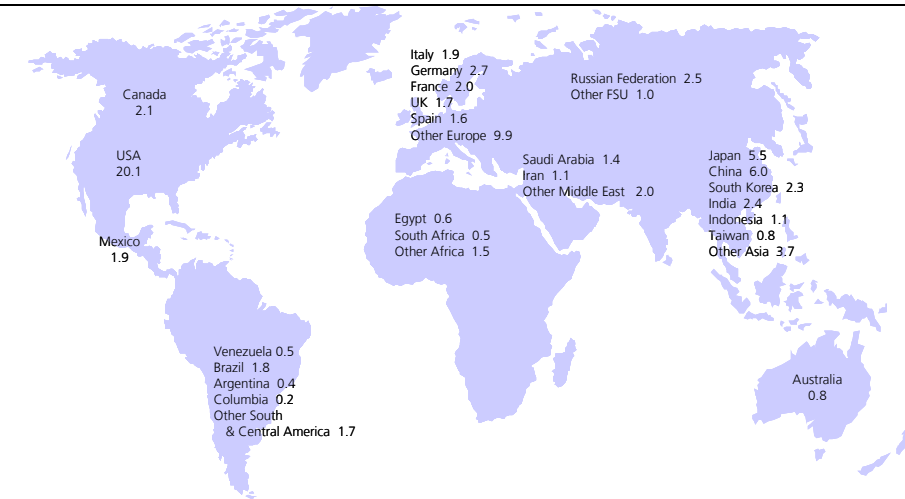
Chart 10: US & China: Energy intensity against GDP per capita (\$)



Source: Thomson Financial Datastream, BP Statistical Review, UBS estimates

It follows that most of the world's consumption occurs in North America, Europe and Asia. Latin America, Africa, the Middle East and the former Soviet Union together account for just 20% of global demand.

Chart 11: Global oil consumption, 2003 (million barrels per day)



Source: BP Statistical Review

What do they use it for?

There are three main, energy-related uses for oil: **transportation, power generation, and heating**. There is also non-energy or process use, for example feedstock for the petrochemical industry. Frequently, the three non-transportation uses are referred to jointly as **stationary** uses, while the last two of the energy-related uses are referred to as **under-the-boiler** markets.

Although energy demand for each end-use responds in broadly the same way to the level of economic activity, there is a marked difference between the end-uses in their vulnerability to fuel substitution. The transportation and non-energy markets have a low vulnerability, making these relatively captive markets for

There are three main, energy-related uses for oil: **transportation, power generation and heating**

oil. However, many energy-related, stationary markets can easily switch between fuels, especially between gas, coal and oil, so their short-run price elasticity is high.

There are significant regional differences in sectoral mix, and therefore in product mix too. The mature economies of the OECD have developed distribution infrastructure for other fuels, are less energy-intensive, have more service-oriented economies, and have high standards of living that support high levels of private mobility. Gasoline, jet fuel and distillate therefore account for a high proportion of their demand, with residual fuel reduced to just a 10% share. In the developing countries, residual fuel oil's share is still more than double this level.

America's love of the automobile, its vast size and its relegation of fuel oil to the margins of the energy market have made the US the most gasoline-oriented market in the world, with US gasoline accounting for 45% of world gasoline demand.

The importance of heating oil, propane and kerosene as northern hemisphere heating fuels makes world oil demand seasonal, with a (northern-hemisphere) winter peak. The average 3.5 mb/d swing between the highest-demand quarter – the fourth – and the lowest – the second – creates a structural tendency for world prices to be strongest in the (northern) autumn/fall and weakest in the spring, although this is often offset by other factors.

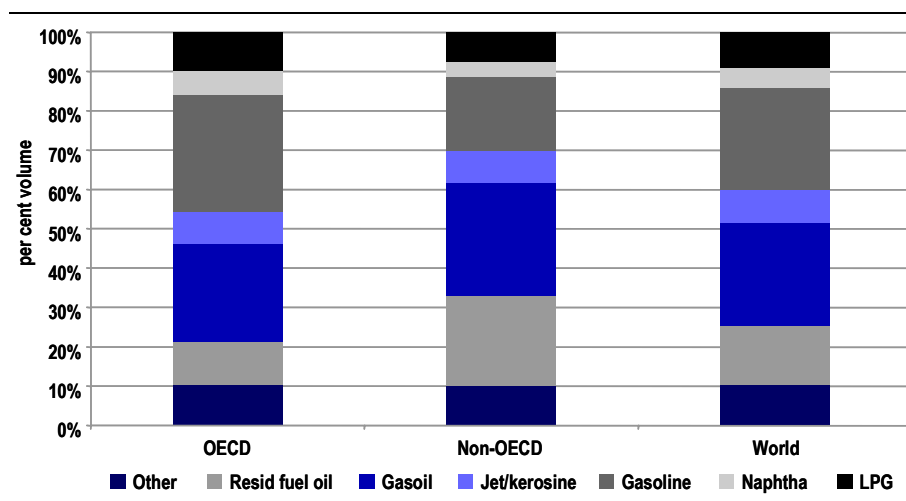
The US, where gasoline is king and where oil's heating role is relatively minor, is the only important region where oil demand peaks in summer, not winter.

The mature economies of the OECD have developed less energy-intensive economies

The US is the most gasoline-oriented market in world

The importance of heating oil makes world oil demand seasonal, with a northern-hemisphere winter peak

Chart 12: World oil demand by product



Source: IEA

Global trends

World oil demand averaged 78.1 mb/d in 2003, a fifteenth consecutive new high, and now more than 17% greater than 10 years ago, helped recently by China's burgeoning economy. This sustained growth parallels the path that demand followed in the 1970s but contrasts sharply with what happened in the 1980s. As that decade began, Middle East instability helped to drive prices to record highs, in what became known as the second oil price shock. Struggling with the repercussions of this price run-up and subsequent recession, world oil demand initially slumped, and then finished the 1980s at a level barely higher than its earlier, 1979 peak.

Globally, oil demand growth has lagged economic growth because the world has become much more energy- and oil-efficient. The US, for example, uses just two-thirds of the energy and half the oil per dollar of GDP that it needed 25 years ago.

Regional trends

Demand in the former Soviet Union (FSU) dropped by 40%, or over 3.5 mb/d, in the first four years after the collapse of communism in 1990, slowing global growth to a crawl. After 1994, as the FSU's demand decline slowed, world growth picked up to 1.6 mb/d annually, tripling its average early 1990s rate. The 1998 Asian financial crisis abruptly and almost completely reversed this pickup.

Asia, with its fast-growing economies, urbanisation and industrialisation, has been the driving force behind the most recent period of sustained growth in global oil demand. It accounted for two-thirds of the nearly 14 mb/d of growth between 1985 and 1997, even though it initially represented less than 20% of global demand. As a result of the deep recession that swept across southeast Asia in 1998, Asian oil demand, instead of maintaining its trend rate of growth of 700,000 barrels per day per year, declined for the first time since 1985. The region has however recovered, with demand in 2003 growing over 850,000 barrels per day due largely to China's oil-intensive growth.

Product trends

The growth in oil demand has been biased toward the higher-quality, harder-to-refine products, as the graph below illustrates. Light distillates (gasoline and naphtha) and middle distillates (diesel, jet fuel, heating oil and kerosene) now account for two-thirds of world oil demand. Each has a market share that is at least double that of residual fuel oil, which has dropped from 23% to 12% in the last 18 years. In the US, residual fuel oil has been almost completely substituted and now accounts for only 5% of US primary energy demand.

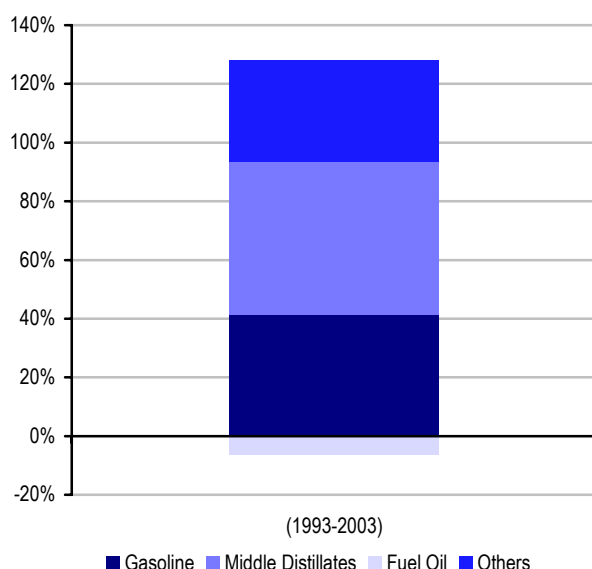
World oil demand averaged 78.1 mb/d in 2003

Globally, oil demand growth has lagged economic growth

Demand in the former Soviet Union dropped by 40%, after the collapse of communism in 1990

Asia was the driving force behind the most recent period of sustained growth in global oil demand

The growth in oil demand has been biased toward the higher-quality, harder-to-refine products

Chart 13: Global product demand trends (1993-2003)

Source: BP Statistical Review

After the two 1970s price shocks, and with the perceived threat of more to come, residual fuel oil in particular lost markets to other fuels. Coal and nuclear, and subsequently natural gas, became economically attractive alternatives, and were therefore able both to dominate new and to displace oil from existing boiler and electricity-generating markets. This made residual fuel oil the only product whose demand has declined over the 1980s and 1990s.

Residual fuel oil has lost market share to coal, nuclear and natural gas

Demand in gasoline's largest single market, the US, went into a tailspin at the beginning of the 1980s, following the introduction of CAFE (Corporate Average Fuel Efficiency) standards in 1975. It fell from a peak of nearly 7.4 mb/d in 1978 to 6.6 mb/d in 1983, greatly amplifying the early 1980s, recession-induced downturn in global oil demand, and allowing distillate to catch up with gasoline in the global demand race.

Since then, distillate has pulled further ahead, despite increased car ownership encouraging North American gasoline demand growth of almost 20% and causing Asian non-Japanese gasoline demand to nearly double over the last decade. The key for distillate was the rapid economic growth in Asia, with diesellisation in Europe making a minor contribution.

Overall, transportation, where gasoline, jet fuel and diesel reign supreme, now accounts for more than 60% of world oil demand, up from under 40% in the early 1970s. Non-energy uses held their share of world oil demand steady over this same period, but energy-related stationary uses lost ground, primarily to natural gas.

Overall, transportation now accounts for over half of world oil demand

The oil price story

In the last 31 years, there have been three sharp, sustained changes in the level of oil prices that have become widely known as *oil price shocks*. These changes were both caused by, and were key contributors to, fundamental changes in the structure of the oil market.

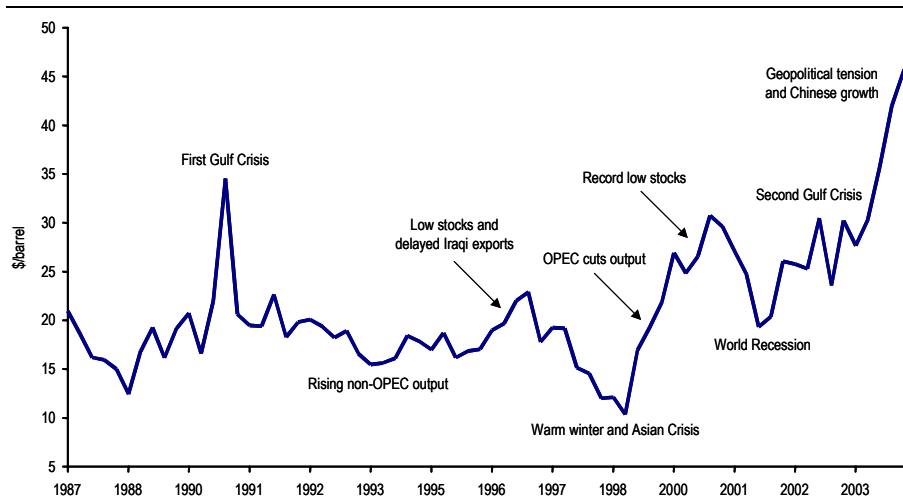
1973 *The first oil price shock*: the Arab oil embargo triggered the 20th century's first significant, sustained increase in oil prices, shattering the consuming countries' complacency about supply security and low prices.

1979/1980 *The second oil price shock*: the Iranian Revolution followed by the Iran/Iraq war triggered a tripling in prices.

1985/1986 *The third oil price shock*: In 1985/86, Saudi Arabia's jettisoning of the swing producer role and adoption of **netback pricing** (see graph) triggered a sharp drop in prices.

There have been four other sharp changes in the level of prices during the period: a jump in 1990 in response to Iraq's invasion of Kuwait, a drop in 1998 in response to the Asian financial crisis and the restart of Iraqi oil exports, and a sharp rise in 1999 following three rounds of production cuts by OPEC and a substantial period of strong demand. More recently, in 2004, China's rapidly expanding economy put strains on the global oil supply at a time of low inventories and supply disruptions stemming from political unrest in the aftermath of the second Gulf War, all of which pushed the oil price over \$50. None of these have been labelled oil price shocks because none were sustained, although it remains to be seen how the most recent pricing environment develops.

Chart 14: Brent oil price 1987–2004



Source: Thomson Financial Datastream, UBS

In the last 31 years there have been three oil price shocks

The third oil price shock effectively divided 1973–98 into two distinct periods:

1973-85: a seller's market. Even though both nominal and real prices were at clear 20th century highs (7-8 times and 2-3 times, respectively, above prior peaks), the consensus was that they would go much higher. Projections that the new millennium would be ushered in with \$100/bbl (nominal \$) oil were widespread.

1986-98: a buyer's market. Prices were significantly weaker than in the first period, although they stayed above pre-1973 levels. Prices were also significantly more volatile because, as both consuming and producing countries shifted toward a much greater reliance on market forces, and as OPEC became weaker, oil prices became a more direct function of normal supply and demand. Oil became a commodity.

Netback pricing

By 1985 Saudi Arabian oil output had fallen sharply as OPEC reined in production to support the official OPEC prices as production rose rapidly around the world.

The Saudi response to this was to introduce a pricing system whereby instead of charging refineries a fixed price for oil, they would guarantee a fixed profit per barrel, irrespective of product prices. For example, if the products from a barrel of oil sold for \$20, the Saudis would receive \$18. If the product slate fell to \$10, the Saudis would receive \$8. This inevitably led to a large increase in refining capacity as the refiners knew that no matter what the price of the products sold, their margins would be fixed at \$2. The Saudis recognised that this would inevitably lead to lower prices, but felt that higher volumes would more than compensate.

Unfortunately for the Saudis, other producers began to copy their 'netback' arrangements, with consequent falls in oil prices. The Saudis believed that these price falls would be limited as marginal producers moved into loss and reined back production, and for a short period of time E&P expenditure did fall quite dramatically. However, with high marginal tax rates for many of the producing fields, not least in the North Sea where much of the new production was coming from, the main losers were national governments rather than the producers themselves. Production continued to rise as prices fell.

In April 1986 George Bush, then vice-president of the United States in the Reagan administration, flew to the Middle East, ostensibly to talk about security issues, although whilst there he brought up the possibility of the US imposing tariffs on oil if the price were to fall – although this was not a view officially sanctioned by the White House. In December 1986 the OPEC oil ministers met in Geneva and agreed quotas to support a recovery in the oil price to \$18.

By 1985 Saudi Arabian oil output had fallen sharply

The Saudi response was to introduce a pricing system whereby refineries received a fixed profit per barrel; this inevitably led to a large increase in refining capacity

Production continued to rise as prices fell

In December 1986 the OPEC oil ministers met in Geneva and agreed quotas to support a recovery in the oil price to \$18

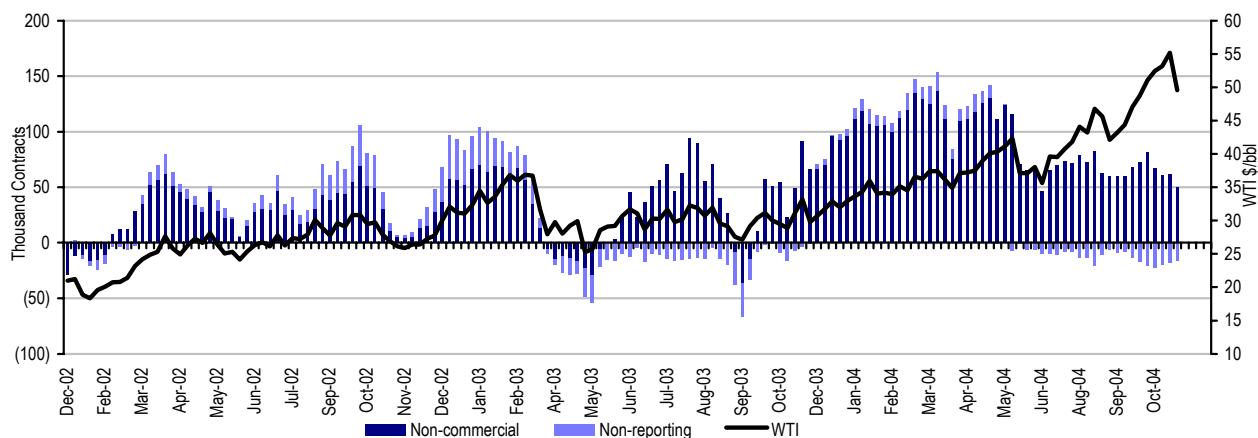
The role of the speculators

Each week, oil markets keenly await publication by the Commodity and Futures Trading Commission (CFTC) of weekly open interest data, released at 3.30pm Eastern Time on Fridays. Open interest refers to the number of open futures or options contracts that are yet to be closed out through either an offsetting transaction, delivery or exercise, with options positions counted in futures-equivalent terms.

All futures positions are reported to the CFTC, with the positions of individual traders classified either as 'commercial' or 'non-commercial'. Commercial positions relate to trades entered into for hedging purposes, whereas non-commercial positions are typically held by commodity investment funds and speculators.

Since early 1994, changes in the net long or short positions of the non-commercials in the NYMEX crude futures contract have coincided with major movements in oil prices, as illustrated in the graph below. Claims that the influence of the speculators outweighs that of the supply/demand fundamentals are unconvincing. But there can be little doubt that the net position of the funds in the market has become a useful coincident indicator.

Chart 15: Combined net short/long positions by trader category 2002-04



Source: CFTC, UBS estimates

Oil sands

What are oil sands?

Oil sands, sometimes referred to as tar sands, are very different from conventional oil and natural gas deposits. Unlike conventional oil, oil sands are deposits that are composed mainly of sand along with a mixture of clay, water and bitumen. These deposits have been found all over the world, but the two largest are the Athabasca oil sands in northern Alberta, Canada and the Orinoco River deposit in Venezuela. Using current technology, the Athabasca oil sands are estimated to contain over 300 billion barrels of recoverable bitumen (from a total of 1.6 trillion barrels in place) and the Venezuelan deposits have been estimated at 1.2 trillion barrels in place. These deposits combined amount to more than twice the reserves in Saudi Arabia. Although they have been known about for well over a century, only recently has the technology existed and the oil price been consistently high enough to make them economically viable, not least because two tonnes of oil sand must be processed to produce a single barrel of oil. This, coupled with dwindling conventional reserves, supportive fiscal regimes (particularly in Canada), as well as economies of scale emerging from the larger projects currently underway, have all resulted in a large degree of recent activity in this hitherto under-utilised resource.

Oil sands are deposits of sand, clay, water and bitumen

There is a lot of variation between deposits, and also within each individual reservoir, as to the amount and percentage of sand, water and bitumen that is contained. The saturation of the bitumen in the sand varies, typically, from zero to 18%. More than 10% is considered to be rich oil sand, from 6-10% is moderate and less than 6% is lean.

There is a lot of variation between deposits, and also within each individual reservoir

The recovery process

Although oil sands represent huge deposits, the oil is not easily produced, as the bitumen that the sands contain is viscous and so does not flow at room temperature; also, the bitumen must be separated from the sand and then converted into crude or products. It is these challenges that have, until recently, prevented the oil sands from being developed.

Open-pit mining or in-situ production is used to recover the bitumen

Specifically, within an oil sands deposit, each grain of sand is surrounded by water containing fine particles of clay and other trace elements. The bitumen surrounds the sand and water. The challenge is to recover the bitumen, which includes separating it from the sand and other materials. The choice of how to do this depends on how deep below the earth's surface the deposit is located.

Surface mining

Shallower oil sands deposits can enable the use of open-pit mining techniques. Due to the cost and technical difficulties involved, this method is only economically practical where the overburden (the layer of sand, gravel and shale which covers the deposit) is less than 75 meters thick. In this process, the overburden is removed and the unconsolidated oil sand is then mined, typically using a truck and shovel approach. The next step is to separate the bitumen from the mix of water, sand and clay that has also been recovered, which can be accomplished by mixing the sands with hot water, steam and caustic soda. Most

Surface mining is only economically practical where the overburden is less than 75 meters thick

of the bitumen rises to the top of the hot water as froth that can be collected for further processing. Huge centrifuges (high-speed rotating equipment used to remove water, clay and sand from the diluted bitumen) and inclined plate separators (essentially a large corrugated filtering device used for the same purpose) take the froth and separate it again into water and bitumen. Other secondary processes further clean and separate the bitumen, sand and water.

In situ

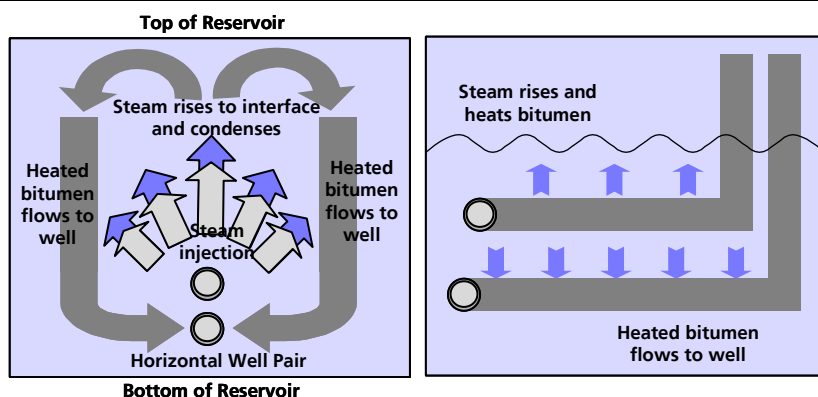
Development of deeper deposits depends on something called 'in situ', meaning in-place production. The primary technique proven to work on a commercial scale is steam injection, whereby steam is injected into the well to heat the surrounding oil, encouraging it to then flow back into the same well where it can be brought to the surface. In situ technology has the advantage of being well suited to development in small increments and leaves a smaller environmental footprint than mining.

Development of deeper deposits depends on 'in-situ', or in-place production

Steam injection

Steam-assisted gravity drainage (SAGD) is potentially the most successful method of steam injection because it significantly improves bitumen recovery rates over the more elementary single-well steam injection methods and therefore lowers costs of production. SAGD involves drilling two horizontal wells one above the other. The upper well is used to introduce steam into the oil sands. As the bitumen thins and separates, gravity causes it to collect in the parallel lower well where it can be pumped to the surface. Further processing is then required for the mix of recovered materials, especially removing the water that results from injecting steam.

Figure 2: SAGD process



Source: Husky Energy

As these in-situ techniques are highly energy-intensive, additional methods of recovery and separation of the oil sands are currently being developed which are less reliant on the already stretched North American gas resources.

The need to upgrade

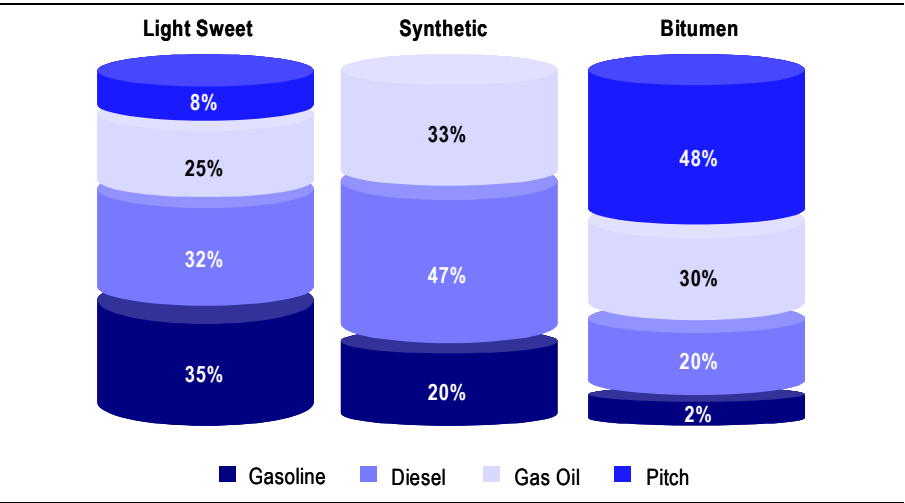
The bitumen from the oil sands has no uses in its raw state, and therefore is of little or no value. This is because, with an API gravity of less than 14 degrees, the bitumen is extremely thick and tarry, with many impurities; it is almost impossible to burn and cannot be refined into normal petroleum products. As a result, the bitumen needs to be upgraded by either removing most of the carbon, a process known as coking, or adding hydrogen, a process known as hydrogenation or hydrocracking. Coking, or carbon removal, is the cheaper and therefore preferred technique; however, hydrogen addition produces more output from the same input and leaves fewer by-products. Both of these techniques result in a high-grade synthetic crude oil, since most of the sulphur has been removed, and it is a product that is acceptable to conventional refineries. However, this comes at significant cost as these upgraders cost several billion dollars.

Overall, synthetic crude oil (SCO) has two principal advantages over light crude: it has a very low sulphur content and it produces very little heavy fuel oil. Among the disadvantages of SCO in conventional refineries are the low quality of distillate output, the need to limit SCO intake to a fraction of total crude requirements, and the high level of aromatics (benzene) that may have undesirable environmental properties.

Bitumen is used to make synthetic crude oil

Synthetic crude oil has two principal advantages over light crude: very low sulphur content and it produces very little heavy fuel oil

Chart 16: Typical crude refining values



Source: CAPP

The future of the oil sands

In Venezuela the oil sands are currently yielding in excess of 200,000 barrels per day and in Canada the oil sands have yielded 4.2 billion barrels of oil to date, at a current rate of a million barrels a day. Both Canadian and Venezuelan production rates are forecast to double by 2010, and Canadian production alone could even reach three million barrels a day by 2020.

Being geographically and politically close to the US, the oil sands are in an advantageous position to warrant further investment and development, which, coupled with falling production costs, a consistently high oil price and favourable tax regimes, assures the future of these unconventional deposits.

World gas markets

Natural gas is the world's third-largest source of primary energy, accounting for 24% of global energy use in 2003. This share is expected to continue to increase as environmental pressures and technical advances provide strong incentives to choose gas, particularly for power generation. Furthermore, as indigenous resources decline, the scale of the international gas trade will increase, enabled partly through the development of LNG technology.

Natural gas, also known as methane, is a colourless, odourless fuel that burns cleaner than many other traditional fossil fuels. It is used for heating, cooling, production of electricity and finds many uses in industry.

Natural gas is produced, sometimes along with oil, by drilling into the earth's crust where pockets of natural gas were trapped hundreds of thousands of years ago. Once the gas is brought to the surface, it is refined to remove impurities like water, other gases, and sand. Then it is transported through large pipelines that often span continents. Factories and electric power plants may get gas directly from the pipeline using arrangements made through a marketer or supplier. Residential and smaller businesses generally buy gas from a local distribution company or utility. The distributor adds an odorant to the gas as a safety measure so that people will be able to tell if there is a gas leak.

Where is it?

Global natural gas reserves are now only 3.5% smaller than global oil reserves. However, this approximate parity is a fairly recent development. Gas reserves have grown by almost 30% over the last decade in part because companies in some cases have started to explore for gas in its own right, whereas historically most gas had been found accidentally when the real exploration target was oil. Oil reserves over the same period have stayed almost flat.

Natural gas demand has not kept pace with discoveries in recent years, largely because it is significantly more expensive to develop new markets for natural gas than for oil, due to the costly infrastructure required, especially if LNG is involved. This has led to large volumes of what is known as '**stranded gas**', gas that has little or no value because it has no immediately identifiable market to go to. Consequently, the R/P ratio for natural gas, at 67 years, is more than 50% higher than oil's.

One reason that natural gas has found increasing favour with consuming governments in recent years is that only one-third of the world's gas reserves are in the politically unstable Middle East, whereas almost two-thirds of the world's oil reserves lie there. In addition, Europe is connected by pipeline to the former Soviet Union, which has the largest share of global gas reserves at 38%.

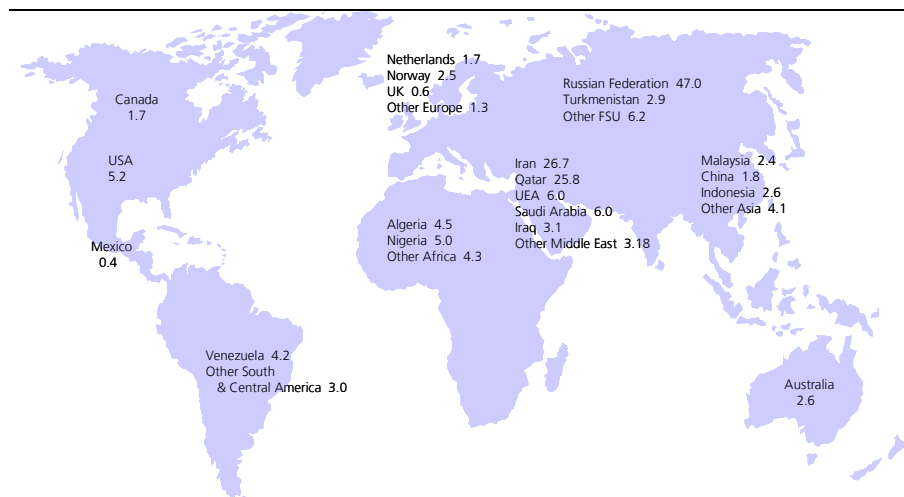
Natural gas is the world's third-largest source of primary energy

Gas burns cleaner than many other traditional fossil fuels

Global natural gas reserves are now almost as large as global oil reserves

Natural gas demand has not kept pace with discoveries, leading to large volumes of 'stranded gas'

One-third of the world's gas reserves are in the Middle East, compared with two-thirds of oil reserves

Chart 17: Distribution of proven gas reserves, end 2003 (trillion cubic metres)

Source: BP Statistical Review

Who produces it?

World gas production grew by 3.4% in 2003, to 253 bcf/day (billion cubic feet) (46mboe/day) (million barrels of oil equivalent), continuing the upward trend that has led production to nearly double in the last 25 years. In the last decade, gas production has grown slightly faster than oil production, and is now equivalent to just under 60% of the level of world oil production.

As already mentioned, North America is the world's largest producing area, as it has been for decades. However, it has steadily lost market share, because its production has grown by less than 10% in the last 25 years. Even though FSU production was undermined by the collapse of communism in 1990, and is still 5% below its 1990 peak, it is the FSU whose share of global gas production has grown the most at the expense of North America. There is a real possibility that the FSU could challenge North America for the number one producer spot within the next couple of years.

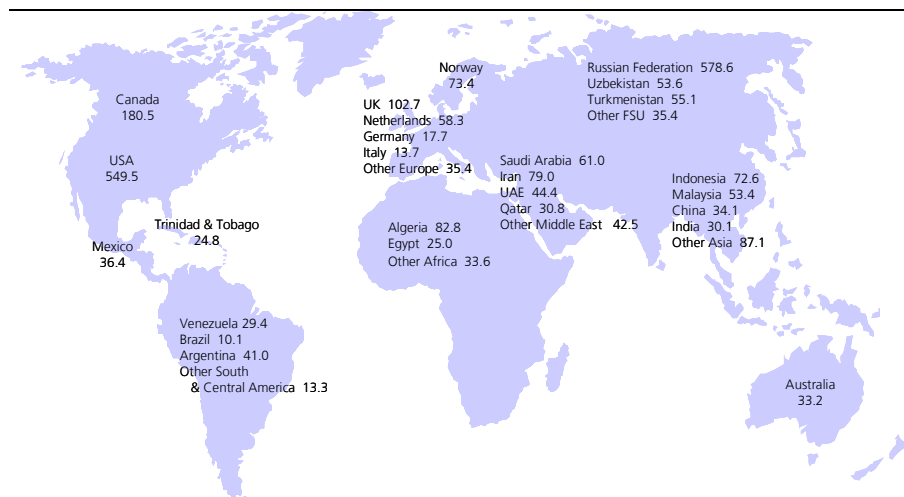
These two are the producing giants of the natural gas world. Beyond them, no single country accounts for more than a 7% share of production and no region accounts for more than 12%.

These production data exclude volumes that are flared or recycled. Historically, the amounts of gas flared in some countries were substantial because markets were insufficient so that the gas had little or no value, and environmental concerns were less developed. That situation has been changing rapidly, and the volumes of gas flared today are much smaller and on track to being eliminated.

World gas production has nearly doubled in the past 25 years

North America is the largest producing area, closely followed by Russia

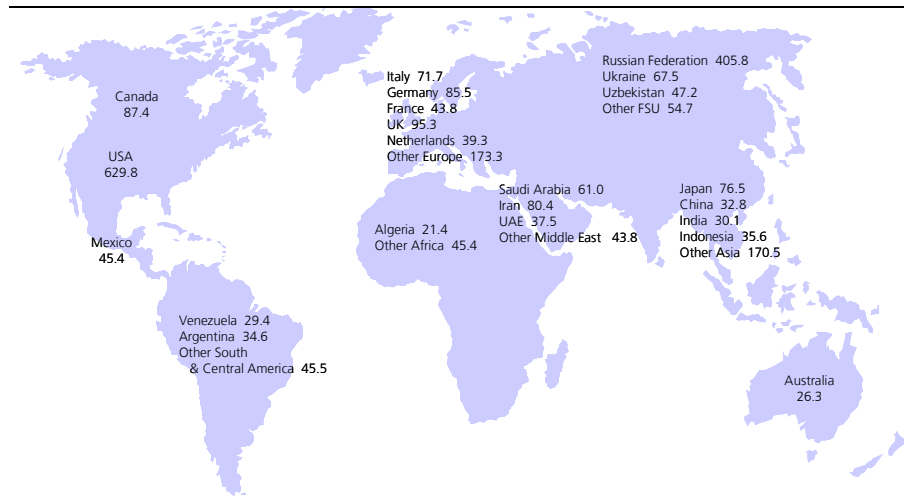
No other country accounts for more than a 7% share of production

Chart 18: Global gas production, 2003 (bcm)

Source: BP Statistical Review

Who uses it?

World gas consumption increased by 2% in 2003, to 251 bcf/day. Consumption increased in every region other than North America, where gas demand has grown by less than 10% in the last 25 years. In contrast, it has more than doubled in Europe and grown sixfold in the rest of the world, as new domestic and import sources have opened up.

Chart 19: Global gas consumption, end 2003 (bcm)

Source: BP Statistical Review

The North American natural gas market

US supply

US production

Declining US production – down 1.3% per annum over the last five years – has been the primary factor behind rising North American natural gas prices in recent years. At present, US natural gas demand is met largely by six major supply basins: the offshore Gulf of Mexico, the Gulf Coast onshore, the Mid-continent, the San Juan Basin of New Mexico, the Rocky Mountains, and Canada. Due to their differing proximities to consuming regions and pipeline infrastructure, the realised price for natural gas in these respective regions varies widely. Generally, the Appalachian, Gulf of Mexico and Gulf Coast production sells at a premium to the other regions due to the large local market and vast pipeline infrastructure in the area.

Canadian imports

Canadian imports of natural gas climbed from 2 bcf/d in 1986 to over 10 bcf/d currently. For a good part of the 1990s, Canadian import growth met nearly two thirds of US demand growth. However, it now appears that increasing depletion rates and declining prospect sizes have flattened the production profile for Canadian natural gas. This emerging trend has contributed to the anaemic North American supply outlook, fuelling rising natural gas prices.

Other supply sources

Given the weak outlook for North American natural gas production, LNG imports appear to be the most likely source of supply growth over the medium term. Over 40 regasification plants have been proposed (four exist currently), and they would source supply from regions such as Trinidad, Algeria, Australia, Qatar, and the UAE. LNG imports are currently 2 bcf/d (3% of demand) but projected to meet over 10% of demand by 2010.

Storage: seasonal swing supply

Natural gas storage facilities are used to meet peak demand during winter. In the United States, there are approximately 400 natural gas storage facilities offering working gas capacity in excess of 3.3 Tcf. These storage facilities are depleted reservoirs converted to store natural gas such as salt caverns or some type of aquifer.

The natural gas inventory cycle is broken into two segments: the winter heating season and the injection season. The winter heating season begins on 1 November and runs through 31 March. During this time, storage levels are drawn down to meet increased winter demand. During the winter heating season, storage usually meets 18% of demand. The refill season runs from early April through end-October. During these months gas is injected into the storage facilities for the coming winter. During the refill season approximately 17% of supply is injected into storage.

The most important development on the supply side in recent years has been the increase in Canadian imports into the United States

The United States also imports gas via liquefied natural gas (LNG)

Natural gas storage facilities are used to meet peak demand during the winter

The natural gas inventory cycle is broken into two segments: the winter heating season and the injection season

Official storage data from the EIA is issued both weekly and monthly. Although historically this data has been less than 100% reliable, it offers the only timely insight into US natural gas supply/demand trends. The NYMEX futures contract has often traded off this storage data.

US demand

There are four major components of natural gas demand in the United States:

- residential
- commercial
- industrial
- electric utility

In 2003, residential demand accounted for 23% of total demand, commercial 14%, industrial 37%, and electric utility 22%. Natural gas competes with coal, oil and electricity to supply these end-markets.

The key factors that typically drive demand are weather, (affecting residential and commercial demand in winter; electric utility demand in summer), price, (affecting industrial and electric utility demand year round), and industrial activity.

During the winter heating season, weather is the key driver of demand for the residential and commercial segments. Cold weather increases natural gas demand for heating purposes. During the summer months, weather is the key driver of electric utility demand, as gas is used by electric utilities to generate electricity for air conditioning.

The sectors most sensitive to price are the industrial and electric utility sectors. These two sectors are generally capable of switching energy feedstocks. Typically they can burn either natural gas, residual fuel oil (resid), or heating oil. As one feedstock becomes more expensive than the other, large industrial users and electric utilities can change to the more competitively priced fuel. Also, typically these users will switch fuels seasonally such that, in winter, when interruptible pipeline capacity is short, they will burn residual fuel oil rather than gas. (Many users do not subscribe to firm pipeline capacity. They rely on released and interruptible pipeline capacity, which tends not to be available in the winter). Inter-fuel competition is thus most intense in resid and gas. Electric power plants capable of fuel-switching are old and are being retired. The new plants are not capable of switching to resid.

Residential demand for gas

Residential demand is very weather-sensitive. The bulk of gas consumed in this sector is used for home heating – particularly in the Midwest and the Northeast. Demand runs less than 4 bcf/d in the summer (when gas is used for the small demand created by home cooking, water heating, and clothes drying) but exceeds 35 bcf/d on the coldest of winter days when residential furnaces are running flat out.

There are four major components of natural gas demand in the United States: residential, commercial, industrial, electric utility

The key factors that typically drive demand are weather, industrial activity and gas pricing

The demand sectors most sensitive to pricing are the industrial and electric utility sectors

Residential demand is very weather-sensitive

Commercial demand for gas

Commercial demand also has a weather component. Summer demand is in the 4-5 bcf/d range while winter demand typically averages 15 bcf/d. Gas is consumed by hotels, restaurants, shopping malls, airports, light manufacturers and office buildings for space heating, water heating, cooking and, in a few cases, air-conditioning. Gas consumed by Natural Gas Vehicles (NGVs) is also accounted for in this sector.

Much like residential demand, the key regions for commercial demand are the Midwest and Northeast. Thus, cold winter weather in these two regions is critical to total US commercial demand.

Industrial demand for gas

Industrial demand comes primarily from manufacturing sectors such as chemicals, stone, clay and glass production, steel/metal manufacturing, and paper and paper products manufacturing.

After peaking in 1996, industrial demand has been in modest decline for the last seven years, we estimate by 3% per year. Such demand declines have largely been the result of price-induced demand destruction required to balance an exceedingly tight supply/demand balance. For example, industrial demand for gas to fuel fertiliser plants has declined, as natural gas costs (the feedstock in fertiliser production) in the United States are materially higher than in most international markets.

After peaking in 1996, traditional industrial demand has been in modest decline for the last four years

Electric utility demand for gas

Many electric utilities, particularly in Texas, the Southwest, and California, use natural gas as a fuel for generating electricity. Nuclear power, hydro power, distillates, residual fuel oil, as well as coal all compete with natural gas for the demand of raw energy by electric utilities. Some utilities, generally in coastal areas (Northeast, Florida, California) have the capability of switching between natural gas, resid and distillates at short notice, although, as mentioned earlier, the amount of capacity capable of fuel-switching is declining.

US electricity demand growth has averaged over 2% per year on an annualised basis since 1991 and this trend looks set to continue. The additional supply required to feed this demand is expected to be fuelled largely by natural gas. Indeed, this can be seen with electricity supply from this source growing 91% since 1991 while overall electricity supply grew only 25% over the same period.

US natural gas pricing

Much like other parts of the world, natural gas in the US is priced based on energy content and proximity to consuming markets.

Unlike most other parts of the world, the United States has a separate and distinct spot and futures market for natural gas. Natural gas futures are traded on the New York Mercantile Exchange (NYMEX). This is the most widely quoted US natural gas price. The NYMEX natural gas contract calls for delivery at a location in northwest Louisiana called **Henry Hub**. However, less than 1% of all futures contracts are ever held to delivery. Rather, the NYMEX natural gas contract serves as a benchmark for monthly pricing.

Around 80% of natural gas in the US is sold through what is known as the bidweek process. Bidweek (actually just three days) occurs on the three days leading up to and ending on the NYMEX contract's expiration, which occurs on the third-last business day of each month. The NYMEX natural gas contract expiration price sends a clear signal to the gas market of what prices bidweek deals should be conducted at.

The remaining 20% of the natural gas sold in the US is sold in the spot or cash market. Such volumes are simply volumes required in excess of bidweek contracts (or volumes resold in months when demand for natural gas comes in lower than bidweek contract volumes).

Unlike most other parts of the world, there is a separate and distinct spot and futures market for natural gas in the United States

80% of natural gas in the US is sold through what is known as the bidweek process

Exploration and production

Acquiring assets

In the majority of cases national governments own hydrocarbon assets. Exploration acreage is auctioned at regular intervals and generally sold to the highest bidder in the form of a **lease**. The bid often takes the form of a package of commitments to the host country. The packages may include infrastructure development, a commitment to spend a certain amount of money on exploration, the intention to shoot a set amount of kilometres of seismic surveys, or plans to drill a certain number of wells. When acreage is awarded, the fiscal regime often incorporates some form of **production sharing contract** and is usually fixed. Lease durations vary enormously. In the UK, licences are typically awarded for 25 years, whereas in the US they would tend to be much shorter.

In the majority of cases national governments own hydrocarbon assets

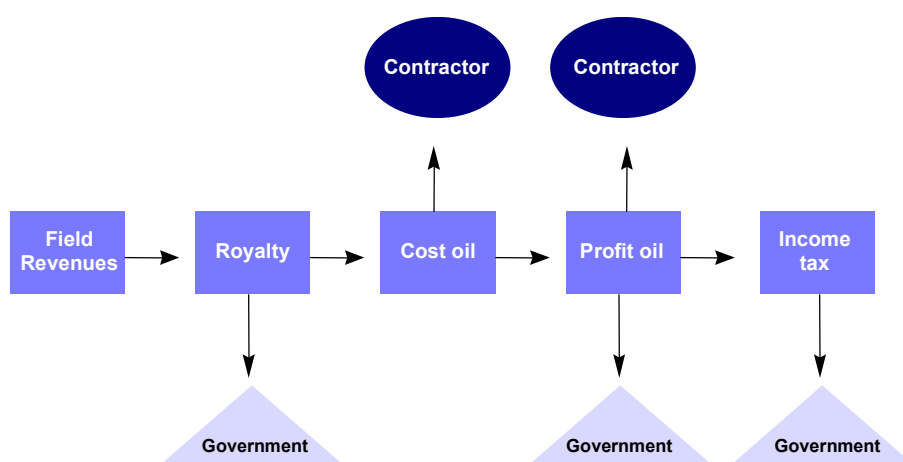
To share the risks and costs associated with exploration wells, acreage tends to be shared between several parties. The company responsible for the drilling development and operation of any discovery is called the '**operator**' and the other companies participating in the project are called 'joint venture partners'.

Fiscal regimes and production sharing contracts

The degree of government tax or 'take' from the oil and gas industry varies enormously around the world, but principally consists of a combination of royalties, profits, and taxation. Government take can be in the form of cash or physical oil. Many tax regimes are based on production sharing contracts (PSC) or Production Sharing Agreements (PSA), whereby the state retains the title to the oil and gas in the ground. The remainder, which include the UK and US, are tax/royalty systems. Most PSCs also have some form of sliding scale terms, depending on production rates, oil prices, reservoir depth or age.

Government 'take' from the oil and gas industry varies enormously around the world, but principally consists of some combination of royalties, profits and taxation

Figure 3: Typical production sharing contract



Source: UBS

Royalties – the cash payment or payment in kind paid to the owner of the mineral rights. Many PSCs do not include royalties. The ones that do usually range from 5% to 15% of revenues, and may be subject to a sliding scale, based on production rates.

Royalties...

Cost recovery – most PSCs allow the operator to recover the costs of exploration, development and operations out of gross production or gross revenues (before profits are split and taxes levied). Cost recovery, known as ‘**cost oil**’ is made up of: operating costs, capital costs (expensed), financing costs, and unrecovered costs carried over from previous years. The revenue remaining after the cost recovery is subject to a ‘**profit oil**’ split between the contractor, his partners and the state (the exact terms of which depend on the terms of the PSC) and is known as profit oil. The contractor split is often related to cumulative production, rate of return or **R factor** (the ratio of cumulative revenue to cumulative costs). This is aimed at giving a higher contractor profit oil early in the field life. Sometimes a price cap is applied on the profit, whereby the contractor’s profit is capped if the price rises above a certain level. Additionally, sometimes the PSC will state that a proportion of the oil must be sold to the domestic market at a lower than market price (eg, in Indonesia).

Cost recovery...

The operator’s share of profit oil may be subject to **corporate taxation** at prevailing national rates and, in some cases, specific **hydrocarbon taxes** – for example, the Petroleum Revenue Tax (PRT), which was in place on new fields in the UK until 1993. Petroleum taxes are usually field specific. Some countries impose a rate of return (ROR) petroleum tax, which ramps up as successive ROR thresholds are reached. **These can result in extremely high government takes (~95%) at very high profitability, and can even result in NPVs declining for increases in production and price in exceptional circumstances.**

Corporate tax...

Windfall taxes – these are rare. They were last used in the UK in 1981/82 – the Supplementary Petroleum Duty (SPD) when oil prices exceeded \$35/bbl.

...and, in rare cases, windfall taxes

Service contracts – in some places the contractor receives a fixed fee per barrel. For example, in Nigeria, Shell receives around \$2.50/barrel margin, while in Abu Dhabi (Total, BP and Shell) margins are fixed at around \$1/bbl.

In some places, Nigeria and Abu Dhabi for example, the contractor receives a fixed fee per barrel

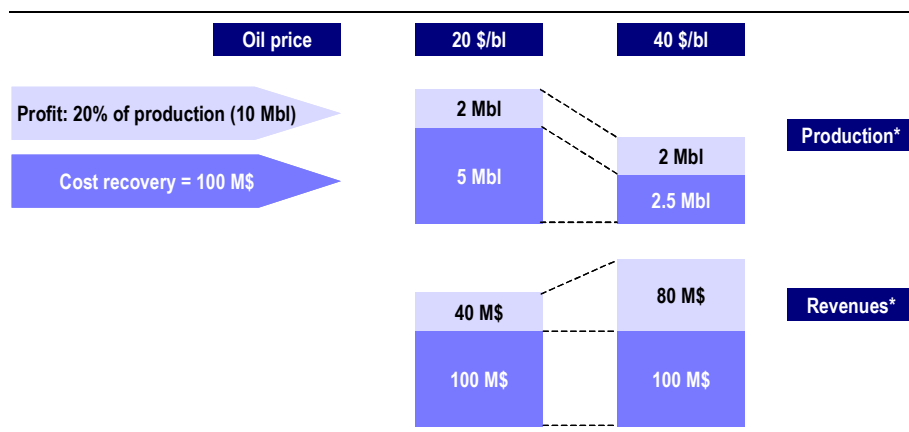
PSC effects

PSCs can effect a company’s reported production as the oil price changes. In particular, in a high oil price environment, reported production is reduced through these ‘PSC effects’. Chart 20 illustrates this situation. In this example overall production for the period is fixed at 10m barrels, the company’s cost recovery is \$100m and the PSC contract stipulates profit oil for the company of 20% of total production.

In the first situation, the oil price is \$20 per barrel, suggesting that the company will need to collect the revenue from 5m barrels of oil to recover its costs. A further 2m barrels constitutes profit oil for the company under the terms of the contract, leaving the revenue from 3m barrels for the local government. Overall company production here is 7m barrels.

In the second instance, the oil price is \$40 per barrel. Consequently, the company's cost oil is now only 2.5m barrels, however, its profit oil is unchanged at 2m barrels, as stipulated in the PSC. In this case, the government's profit oil has grown to 5.5m barrels. Overall production for the company here is 4.5m barrels.

Chart 20: PSC – price effect

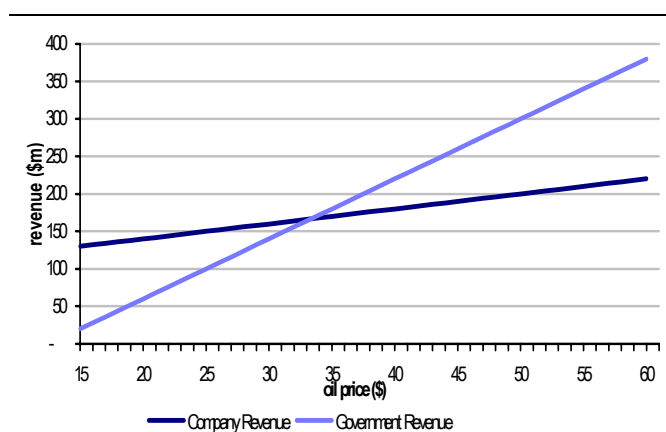


Source: Eni company presentation

Despite falling reported production, the oil company is still better off in the higher oil price environment. In the first instance, with oil at \$20, the company's total revenues are \$140m (7m x \$20). In the second case with oil at \$40, the company's total revenues are \$180m (4.5m x \$40). It is of note, however, that the biggest winner from oil price inflation is the local government whose revenues increase from \$60m to \$220m. The following charts depict this relationship.

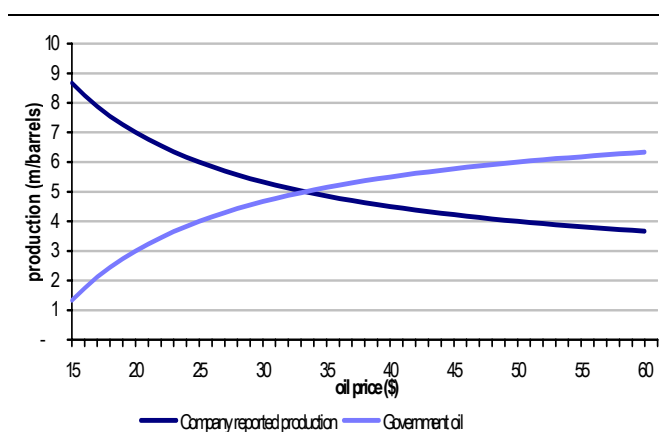
Despite falling reported production, the oil company is still better off in the higher oil price environment

Chart 21: PSC revenue



Source: UBS

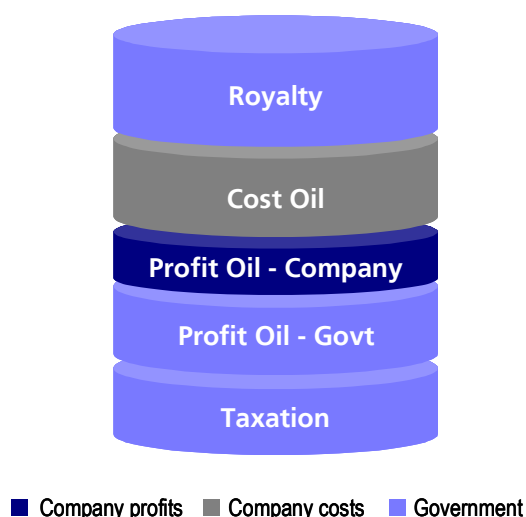
Chart 22: PSC production



Source: UBS

Figure 4 shows a typical example of a PSC, showing the average returns to the government and the company over the field life.

Figure 4: Typical production sharing contract



Source: Royal Dutch/Shell

Upstream performance measures

The most important measures of upstream performance are finding and development costs, production costs, reserves replacement and technical costs.

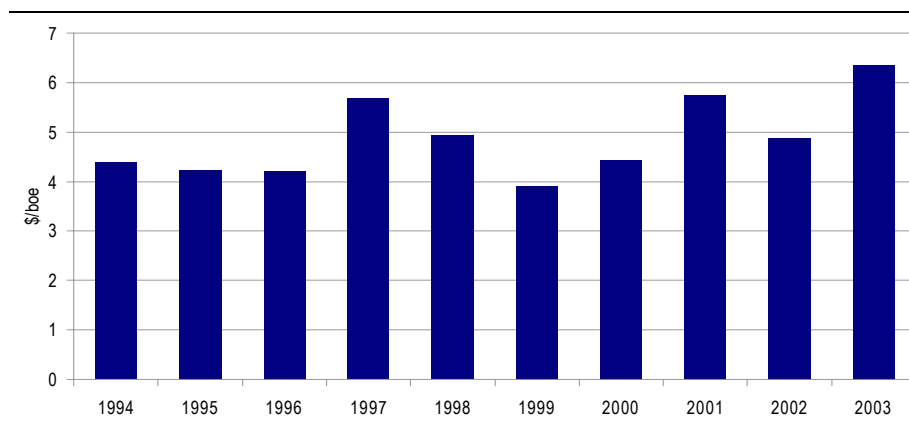
Finding and development costs

Finding and development costs are generally quoted on a per barrel of oil equivalent basis (boe). **Finding costs** comprise the costs of the exploration and appraisal programmes alone. **Development costs** are the costs of constructing and installing the facilities to produce and transport the oil and gas to the sales point.

Finding and development cost calculations compare the money spent to add reserves with the actual reserves added. There are four categories of expenditure: three form part of the broad exploration and development cycle (acquisition of acreage, exploration of that acreage and development of any successes), while the fourth category is the purchase of existing reserves. These costs are divided by the reserves added during a given time period to arrive at a \$/boe finding cost.

Finding and development costs rose 31% in 2002 alone and have continued to rise since, as reserves added fall and finding and development expenditure increases as shown in Chart 23.

Finding and development costs include all capital and revenue costs incurred prior to production

Chart 23: Finding and development costs

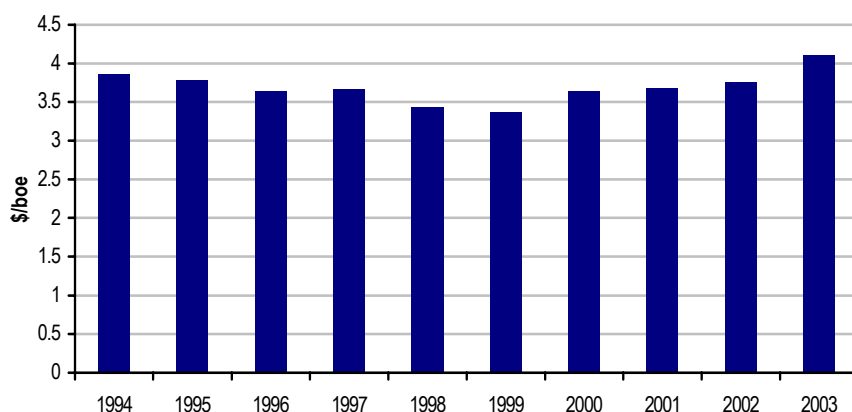
Source: Company accounts, UBS

Production costs

Production costs – sometimes known as lifting or operating costs – comprise staff costs, on-site energy costs, rental of capital equipment (rig hire, etc.) and consumables such as drilling mud, drill bits, etc.

Production costs of the major integrated oil companies fell steadily in the 1990s, as a result of improved technologies (horizontal drilling, subsea developments, FPSOs, etc.) and lower royalties (sometimes included in production costs). However, between 1999 and 2003 production costs have risen by 22%.

Production costs comprise staff costs, on-site energy costs, rental of capital equipment and consumables

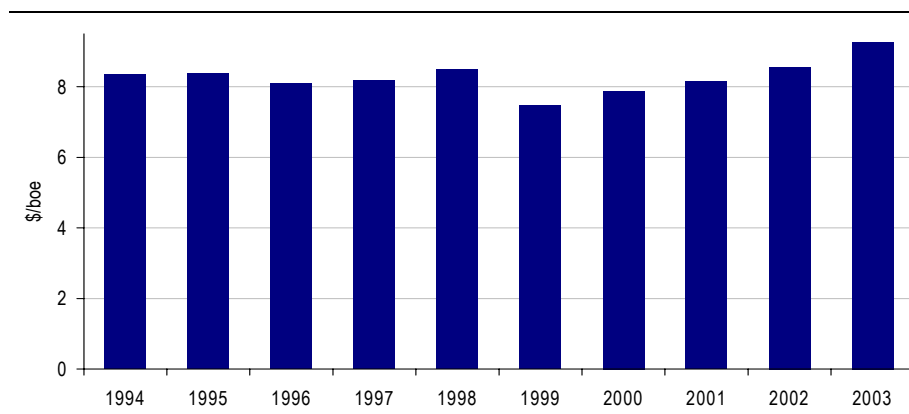
Chart 24: Production costs

Source: Company accounts, UBS

Technical costs

Technical costs include exploration expenses, depreciation, depletion and amortisation (DD&A) and production costs; and therefore, a number of non-cash items. Technical costs, like finding and development costs are quoted on a per barrel of oil equivalent basis. Chart 25 shows that between 1999 and 2003, technical costs for the major integrated oil companies increased by 26% to \$9.27/boe, continuing the recent trend of rising costs after a long period of successful cost reduction.

Technical costs include exploration expenses, DD&A and production costs

Chart 25: Technical costs

Source: Company accounts, UBS

As the preceding charts show, finding and development, production and technical costs are all currently rising. This is partly due to dwindling production from mature fields, which increases the capex and opex necessary to maintain production from ageing facilities.

Finding and development, production and technical costs are all currently rising

Additionally, as fields mature, companies intensify the search for new reserves, which are becoming scarcer. This scarcity of easily accessible reserves is demanding that exploration be carried out away from areas with established infrastructure to deeper and more remote sites, adding to both exploration and operating expenses. The combination of this scarcity of new reserves and a high oil price environment (which is manifesting itself in a greater demand for exploration) has lead BP to estimate that oil service company costs are rising at 5% higher than the rate of inflation.

Instead of searching for new reserves, companies can buy them from competitors. Again, as a result of their scarcity, reserves are also becoming more expensive to acquire, which in turn increases DD&A. These higher DD&A charges result in higher technical costs.

Finally, raw materials such as steel (which is used extensively by oil companies) are rising in cost as the dollar (the default currency of oil company revenues) is falling. These effects act to further squeeze margins.

Fortunately for the oil companies, the significant rise in oil and gas prices has outweighed these cost pressures. Figure 5 illustrates the cost breakdown per barrel and shows that even with an oil price of \$23.50, average net income is only \$7 per barrel. This highlights the vulnerability of oil company earnings to a falling oil price in this rising cost environment.

Figure 5: Typical breakdown of costs from a barrel of oil (2003)

Source: UBS

Reserves replacement

Reserves replacement is another important measure of upstream performance. It is defined as a company's ability to replace production with new finds, upward revisions to earlier reserves estimates (once a field is in production), or acquisitions.

We calculate reserve replacement by using the standardised data provided by the companies as required by the Securities and Exchange Commission (SEC) and Financial Accounting Standards Board (FASB) Rule #69. While there are limitations with both of these, they are the only two standardised measures available that allow comparisons between companies. These limitations stem from the estimation techniques employed to quantify reserves, as such estimates incorporate both geologic and economic factors and are, therefore, open to subjective interpretation. This is dangerous as the value of an E&P company is driven largely by the quantity and quality of its proved reserves. It was precisely this kind of manipulation that has led to the ongoing reserves downgrades that Shell is undergoing.

Produced reserves can be replaced with:

- The discovery of new fields;
- Extensions of existing fields;
- Revisions of earlier reserve estimates;
- Application of improved recovery techniques; or
- Purchases of reserves from others.

Reserves replacement is another important measure of upstream performance

A ratio of 100% indicates that a company has replaced all of the reserves produced during a given period. Since the typical exploration and development cycle is about three to five years long, comparisons of this ratio over shorter time periods are not particularly meaningful.

Reserve estimates are as much an art as a science, and, as new information becomes available, the reserve estimates will fluctuate. Nonetheless, some companies appear to take a conservative approach to reserves and positively revise their reserve estimates over time, while others may tend to book everything at once, and thereby find them subject to subsequent downward revisions.

Neither finding and development costs, nor reserve replacement ratios can be viewed totally in isolation. Clearly, the company that slashes its exploration budget while bringing new fields onstream tends to show lower finding and development costs than the company investing heavily in exploration, which may, eventually, lead to much higher reserve replacement and higher rates of production. Taken to the extreme, the company that neither explores, nor acquires will eventually cease to exist, as fields in production are exhausted.

Upstream accounting issues

There are a number of accounting issues peculiar to the oil and gas sector, and to the treatment of upstream operations in particular. Differing accounting practices makes comparisons between companies fraught with difficulty. Users of accounts should be aware of the inconsistencies.

Full cost versus successful efforts

The biggest difference in accounting policies is in the treatment of exploration expenditure. There are two different accounting conventions in use: **full cost** and **successful efforts**.

Under ‘successful efforts’, exploration expenditure is immediately written off (expensed) if the exploration is unsuccessful. Costs associated with successful exploration, or where results are awaiting further appraisal, are capitalised and depreciated on a field-by-field basis. Conversely, under full-cost accounting, all exploration, appraisal and development expenditure is capitalised in a ‘cost pool’, which encompasses a group of assets or fields.

Over time the P&L impact of the two methods will be the same. Successful-efforts accounting will usually lead to a more lumpy profit profile, but is deemed to be the more conservative approach.

Full-cost accounting companies tend to have higher fixed assets as more exploration expenditure is capitalised, but lower gross profits (before exploration write-offs), as their depreciation charge tends to be higher. However, if a company has a particularly large or particularly unsuccessful exploration programme, the lower exploration write-offs would more than offset the higher depreciation charge, leading to higher net profits.

A ratio of 100% indicates that a company has replaced all of the reserves produced during a given period

There are a number of accounting issues peculiar to the oil and gas sector

The biggest difference is in the treatment of exploration expenditure

Full cost or successful efforts accounting can give different profit profiles...

...although over time the P&L impact of the two methods will be the same

Depreciation in both full-cost and successful-efforts accounting is on a unit of production basis. Hence, the depreciation factor used is annual production divided by remaining reserves; although in successful-efforts depreciation is calculated on a field level, and then aggregated for reporting purposes. Full-cost depreciation is calculated on a pool basis, and then aggregated. Reserves used for depreciation purposes are either proven, in the US, or proven plus probable, in the UK, although estimates of future development capex are included in the UK, which tends to make the unit DD&A charge similar to the US treatment.

Depreciation is on a unit of production basis

Other differences between UK and US reporting, which can be seen when comparing LASMO's and Enterprise's 20-F statements to their UK GAAP numbers (as both companies have ADRs listed in New York), are in deferred taxes, where the US requires full provision rather than the partial provisioning common to the UK.

In general, smaller companies or companies with large exploration programmes relative to their size, tend to adopt full-cost accounting, whereas bigger, more established companies with more diverse portfolios and smoother earnings progressions tend to use successful efforts, being better equipped to absorb fluctuating exploration write-offs. To give an example of the difference in reported profit (which the two approaches can produce) in 1992 LASMO moved from full-cost to successful-efforts accounting and in 1991 restated net income dropped from £82m to £38m.

As a broad generalisation, smaller companies or companies with large exploration programmes relative to their size tend to adopt full-cost accounting

Ceiling tests

For companies using either type of accounting, **ceiling tests**, or impairment tests, are applied to determine whether the net book amount of expenditure within each cost pool or asset (less any provisions for abandonment costs and deferred production or revenue-related taxes) is covered by the company's anticipated future discounted cash flow, using its own forecast of oil and gas prices and discount rates, from the pool or asset. If not, then the company will make additional balance sheet provisions to cover the increased liability. The following extract is taken from LASMO's 1995 accounts.

'The ceiling test results are generally sensitive to changes in assumptions, particularly future oil prices. Taking account of the likely range of future oil prices, the directors have provided £17m in respect of the Piper field group.'

Decommissioning costs and abandonment provisions

Abandonment provisions are becoming increasingly significant, as the cost of decommissioning rises with tightening environmental regulation. Oil companies differ in their disclosure. The majority show *annual* decommissioning provisions, while a few show total abandonment costs to be provided over the life of fields in production. Decommissioning provisions are generally made on a unit of production basis.

Abandonment provisions are becoming increasingly significant as the cost of decommissioning rises

Reserves accounting

The value of an E&P company is largely driven by the quantity and quality of its proved reserves, and the net present value of future cash flows generated from the production of those reserves. Proved reserves generally constitute the vast majority of an E&P company's assets. Consequently, *FAS 69 requires all oil and natural gas companies to disclose proved reserve estimates at year-end*. The operative word is 'estimates' because geologic and economic factors contribute to the determination of reserve *estimates*, most of which are not immune to subjective interpretation, in our view. **Material reserve write-downs/downward adjustments from Royal Dutch/Shell (22% of total reserves), El Paso (35%), Forest Oil (30%), Nexen (8%), and Husky (13%) have highlighted the importance of companies' reserve booking practices.** We have noticed many E&P company managements highlighting lower percentage of proved undeveloped reserves (PUDs), as well as highlighting the increased use of outside engineering firms as a means to independently verify the veracity of their reserves in the wake of the recent reserve scandals.

Other reserve-related information that companies are also required to disclose include the following:

- Capitalised costs related to oil and gas producing activities (ie, net book value of proved reserves and unproved properties);
- Costs incurred in property acquisition, exploration, and development (ie, E&P capital expenditures);
- A standardised measure of discounted present value of net future cash flows of proved reserves;
- Annual changes in measure of discounted future net cash flows related to oil and gas reserves; and
- The results of operations for oil and gas producing activities.

The estimated level of proved reserves plays an integral role in determining a company's earnings and profitability, as oil and gas producers expense the cost of finding, developing, and acquiring reserves on a unit of depletion basis (capitalised costs plus estimated future development costs divided by proved reserves). In the following sections, we outline several key areas of proved reserve reporting, and identify the areas in which E&P companies have the flexibility to be conservative or aggressive with respect to booking reserves, such as the use of outside reservoir engineers in reserve reporting, reserve revisions, and determining the percentage of overall reserves that are proved *undeveloped*.

Reserve reporting – use of outside engineers

Although E&P companies are required to disclose proved reserves under FAS 69, it is optional whether or not a company uses an outside reservoir engineer to estimate or audit the quantity of reserves. Therefore, E&P companies run the full gamut in how (or whether or not) they employ outside reservoir engineers. Proved reserves for companies such as Houston Exploration, Pogo Producing, Spinnaker Exploration, Vintage Petroleum, and XTO Energy are fully determined by outside reservoir engineers. This, in our opinion, is the most

Oil and gas companies must disclose estimated proved reserves, which constitute the bulk of their asset value

In this section, we review the use of outside reserve engineers, revisions, and PUDs

Although required to disclose reserve estimates, the use of outside engineers is optional

conservative methodology, since unbiased third-party experts engineer the reserve estimate. On the other end of the spectrum, Kerr-McGee engineers its proved reserve estimates in-house without a third-party audit or review from an outsider reserve engineering firm. **Not using an outside reserve engineer is not an indictment, nor does it affect the quality or quantity of reserves; however, we believe investors should view this practice as less conservative since the estimates are generated within the company and are not reviewed or audited by an unbiased outside reservoir engineer.** The remainder of our companies fall between these two extremes, with the majority estimating their proved reserves via internal reserve engineers, but employing outside reservoir engineers to audit or review a percentage of their reserves. Notably, several firms rotate properties that are audited or reviewed each year (or quarter) to ultimately cover the entire asset base.

Although recognizing that the SEC has made the use of an outside engineer to audit reserves (or simply ‘sign off’ on the veracity of company estimates) optional, we believe investors should view the use of an outside engineer as a more conservative reserve reporting practice. We liken the use of an outside reservoir engineer to the use of an independent accountant to audit a company’s financial statements. Given that proved reserves represent the vast majority of most E&P companies’ assets, we believe an investor should find additional comfort with independent verification of proved reserves. **Notably, given Sarbanes-Oxley’s requirement for E&P company managements to sign off on the veracity of their financial reports, we have noticed an increased use of outside engineers over the past two years.**

Reserve revisions

Revisions are changes (either upward or downward) to previous estimates of proven reserves. A primary cause for revisions are changes in quarter- or year-end prices, which could shorten or lengthen the economic life of a property and therefore decrease or increase proved reserves. FAS 69 requires constant price and cost assumptions when booking proved reserves; thus, a temporary change in price could have a profound impact on the quantity of a company’s disclosed proved reserves. In other words, a field could be economical when prices are high, but then considered uneconomical as lower prices result in a downward revision to reserves. Thus, it is not atypical to observe downward revisions when reserves are being reported during a period of abnormally low prices (relative to the prior reporting period) and upward revisions during times of unusually high prices. (Note: Companies with production-sharing contracts in foreign countries often experience revisions inversely correlated to commodity price direction; in other words, during periods of rising prices, a company’s net revenue interest in a foreign project will typically decrease, prompting a downward revision to reserves.)

A second cause for reserve revisions is the result of the company recognizing that a given field can physically yield smaller (or larger) amounts of hydrocarbons than originally estimated. Since reserve reporting is a science of estimating, engineers may obtain new (or improved) information from areas, such as well production history and drilling results, that prompt the need for a revision.

Revisions are changes to prior-year reserve estimates

Revisions are generally a result of changes in prices or geologic and engineering assumptions, or changes in field performance expectations

We are cognizant that sharp changes in oil and natural gas prices, which are beyond the control of E&P companies, cause reserve revisions. However, until the industry adopts, or the SEC mandates, a policy requiring companies to break out revisions between price-related and performance-related categories, we believe analysing a company's reserve revisions over time is a useful tool to measure the relative aggressiveness/conservatism of a company's proved reserve bookings. If a company has a string of downward revisions year in and year out, that company may be booking reserves aggressively to boost overall reserves (and investor confidence).

Proved undeveloped reserves (PUDs)

Proved oil and gas reserves are broken down into two categories: proved *developed* and proved *undeveloped*. Proved *developed* reserves are defined as oil and natural gas that can be recovered from existing wells with existing infrastructure and operating methods. The SEC defines proved *undeveloped* reserves as 'reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion'. Thus, *investors should view proved undeveloped reserves as somewhat higher risk than developed reserves for several reasons:*

1. Undeveloped reserves are more difficult to estimate than developed reserves;
2. The estimation of undeveloped reserves is more subjective than that of developed reserves;
3. Undeveloped reserves are the most subject to downward revisions, particularly in a weaker commodity price environment; and
4. Undeveloped reserves require future capital outlays to be brought on production, and, therefore, should be valued less than proved developed reserves, in our view.

Significant exploration discoveries or large-scale development projects are often reported as *undeveloped* reserves and can be viewed as a company's inventory of 'production growth opportunities'. For the reasons stated above, it should be clear that, in general, a smaller percentage of undeveloped reserves is considered more conservative from a 'reserve quality' standpoint. However, some companies on the cusp of significant growth appropriately have a larger percentage of PUDs until new projects come onstream.

Trends in frequency or size of reserve revisions belie a company's conservatism/aggressiveness

PUDs require future capital and infrastructure development before initial production can begin

Given capital requirements and estimation uncertainties, a smaller percentage of PUDs is viewed as conservative

The exploration process

The search for hydrocarbons is now much more scientific than it was in the early days of the industry, but it is still not possible to say conclusively that oil exists in a specific area, much less that it exists in commercially viable quantities. Very approximately, around one in eight wells drilled now finds oil, although this ratio will vary enormously depending on the region and its history.

The first stage in the exploration process is to identify favourable geological conditions where hydrocarbons are likely to exist, often using aerial or satellite photography. Prospective geological structures are identified through geophysical methods. The first stage in the exploration process is to identify sedimentary basins hidden beneath the sea and non-productive rock. This is usually done using relatively inexpensive **gravity** or **magnetic surveys**. Detailed information over a smaller area of interest is then obtained through **seismic surveys**.

The industry uses seismic analysis to identify prospective areas. The data can be used to map the sub-surface strata, generating 'prospects' for drilling. Sound waves are emitted in a prospect area (onshore or offshore) and geophones are used to detect the waves that bounce back from the rock formations. Through complex computer data analysis, these signals are processed and then interpreted to create an image of geological formations and possible deposits of hydrocarbons. On the basis of this analysis, oil companies can make decisions on conducting exploratory and developmental drilling activity.

Specialist contractors perform seismic surveys. These contractors will conduct the survey for a single oil company or a consortium of oil companies, or for their own account (**multi-client survey**). Seismic surveys can be carried out on land or at sea. In offshore areas a ship tows a submerged water gun that generates explosions of sound energy. These penetrate the sea bed and are reflected by the subsurface rock layers back to the surface to be received by hydrophone groups towed by the ship. The procedure is repeated at consecutive intervals and the data collected and processed. Onshore, sound receivers (geophones) are laid out on long strings of cables over the survey area. Sound is then generated either through the use of explosives that have been placed in holes drilled into the ground at precise locations or through the use of large vibrating trucks. The resultant seismic sections are 2D vertical representations of the underground structure. Over the past 15 years, the industry has increasingly adopted a more sophisticated and expensive method of acquiring seismic data, which provides a three dimensional (vertical, horizontal, and orthogonal) view of the Earth's subsurface (**3D seismic**), or includes a time element (**4D seismic**). Seismic surveys taken over a period of time enable the geophysicist to monitor the migration of oil, water, and/or gas through the reservoir and allow for recovery from that reservoir to be optimised.

While we have primarily discussed the role that seismic analysis plays in finding a prospect to be drilled, increasingly over the past decade oil companies have used seismic analysis as more of a field development and reservoir monitoring tool. In fact, the more sophisticated data sets (3D and 4D) and the more sophisticated processing and interpretation technologies are used far more

It is still not possible to say conclusively that oil exists in a specific area until a well is drilled

The first stage in the exploration process is to identify favourable geological conditions

The industry uses seismic analysis to identify prospective areas

frequently during the field development and production phase than during the exploration phase.

Whether it is for exploration or development purposes, seismic analysis is often the precursor to actually drilling wells.

The drilling process

The drilling process is fairly similar whether the well is an exploration well or development well. The main difference is that the oil and gas company will usually take more measurements and try to drill more zones in an exploration well than in a development well, where the target objective is very clear and the reservoir properties are already well known. The other main difference will be in the method of completion that will be employed.

Wells are drilled using a **drilling rig**. Drilling rigs tend to be mobile units that are owned by separate contractors and can be used in a variety of environments: land, transition zones (**barges/submersible rigs**), shallow water depths up to 400 feet (**jackup rigs**) and deep water (**semi-submersible rigs** and **drillships**). The following figures are pictures of the two workhorses of the offshore drilling industry – the jackup rig and the semi-submersible.

A jackup rig is a bottom-supported unit that typically has 3 or 4 legs that are lowered to the point where they penetrate the seabed. Once the legs are secured the hull is jacked up above the sea surface, providing an air gap to offset the effect of waves and current. Many jackup rigs also have drilling packages that can be cantilevered or extended over the edge of the rig, so that the unit can drill through a slot on an adjacent platform. This is very useful for development and redevelopment drilling.

Figure 6: Jackup rig



Source: Rowan Companies Inc.

A semi-submersible rig is a unit that typically has a deck that is connected via columns to pontoons that sit beneath the surface of the water. These rigs can either be moored in place through a series of anchors or can remain in place using a series of computer-controlled thrusters for dynamic positioning. These

rigs are useful for both exploration and development work, and due to the size, ballast and motion control characteristics they are suitable for a variety of water depths and sea-state conditions. Semi-submersible rigs are typically classified by the time frames in which they were built. These time periods or ‘generations’ provide insight into the relative capability of the rig, as a 4th or 5th generation rig will tend to be larger, more efficient, and capable of working in deeper or rougher water than most 2nd or 3rd generation rigs.

Figure 7: Semi-submersible rig

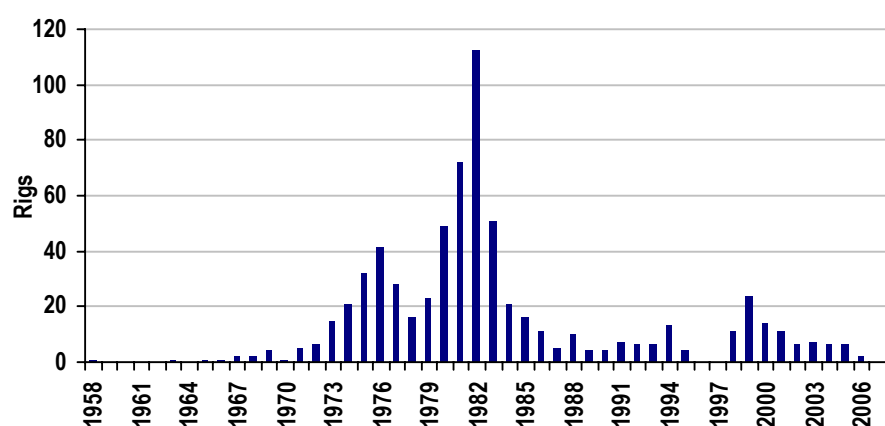


Source: Transocean

Drilling services are usually provided on a **day-rate basis**, where the oil company pays the drilling contractor a certain sum per day until the well is completed or abandoned. There are some drilling contracts that attempt to give an incentive for efficiency: in some cases the contractor is paid on a **footage basis** (a fixed sum per foot drilled) or on a turnkey basis (a fixed sum for a completed well). The majority of the drilling around the world is done on day-rate-related contracts.

Drilling contractors are usually compensated on a day-rate basis

Day rates are typically a function of the supply/demand balance for rigs. Rates tend to range between the amount needed to cover the cash operating costs of the rig in a depressed market and the rate that is high enough to incentivise a contractor to build a new rig. The last widespread newbuilding cycle in the onshore and offshore market was in the late 1970s and early 1980s when the majority of the current active rigs were built. In the late 1990s, there was another mini building/upgrade boom. However, this period was less about growing fleet capacity and more about creating the rigs that were needed to search for oil and gas in deep and ultradeep water depths (5,000-10,000 feet). Because many rigs are similar, rig pricing tends to work off a marginal unit pricing model. The marginal unit of supply or demand often determines whether prices for all units will be rising or falling.

Chart 26: Rigs delivered by year (only those still in service)

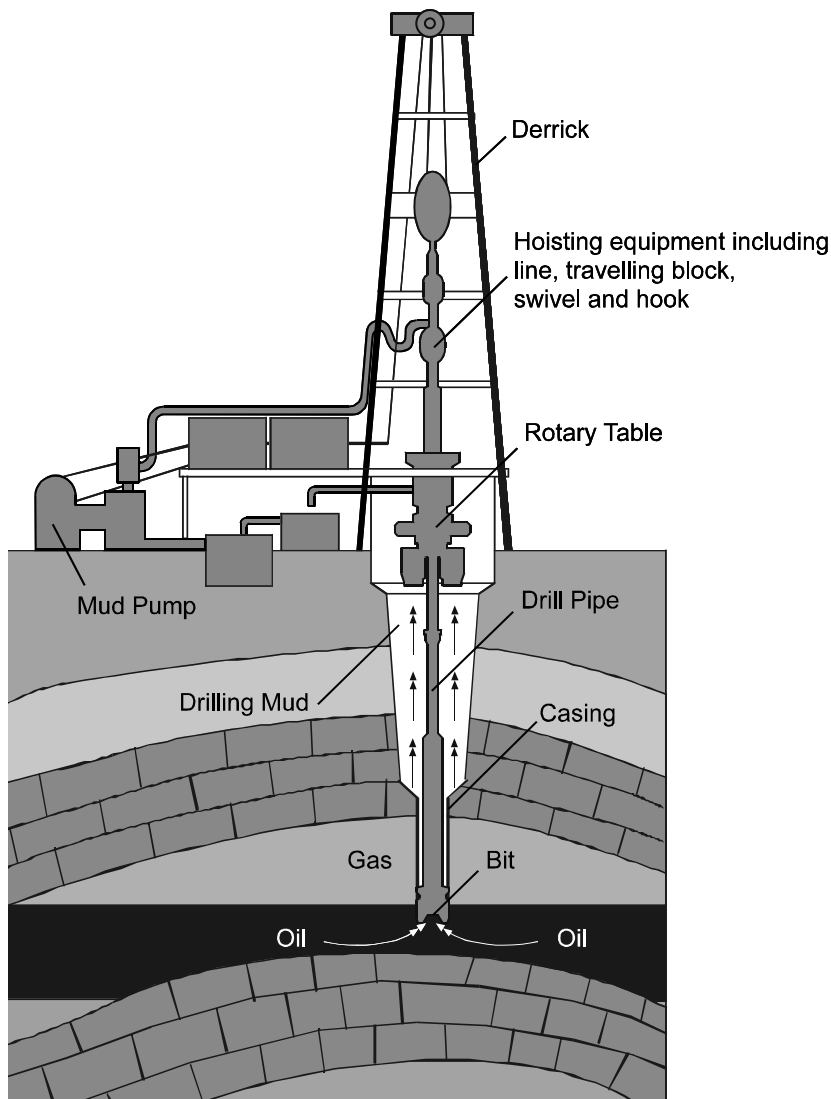
Source: ODS-Petrodata

Most wells today are drilled with rotating **drill bits**, which cut and crush the rock as they descend. There are generally two types of drill bits, **roller cone bits**, which have three rotating cones with protruding teeth. Roller cone bits are still the industry standard for most rock types. However, in the past decade the second type of bit (**fixed cutter or PDC**) has made significant inroads into the market. Fixed cutter bits tend to have synthetic diamond coated inserts (polychrystalline diamond compact (PDC) inserts) that act as the cutting structure of the bit. PDC cutters do not rotate separately like roller cones, but rotate with the whole body of the bit. Fixed cutter bits tend to have a longer wear life and, in many instances, can drill faster and longer than roller cone bits, increasing drilling efficiency and lowering drilling costs.

The drill bit is typically part of the bottom-hole assembly that will often include measurement-while-drilling (MWD) tools and sensors, drilling motors, and heavy weight drill pipe or collars. The BHA will be connected to the rig by a string of **drill pipe** or drill string. The drill pipe transfers the mechanical force of the drill rig to the bit and also serves as the conduit for **drilling fluids** into the well, which cool and lubricate the bit, while carrying cuttings to the surface. The drill pipe stands up and is supported in the rig by the derrick (a tall steel structure shown in Figure 8) and is rotated either with the rotary table or a top drive (a rotating mechanism that is mounted on rails inside the derrick, as opposed to being fixed to the rig floor like the rotary table). Top drives are almost universally installed on offshore rigs and increasingly on land rigs.

The initial drilling of the well is known as **spudding**. During the drilling of the well, as certain geological milestones are reached, the drilling process will be suspended and the well will be cased and cemented. **Casing** the well involves the installation and cementation (cementing is performed by a pressure pumping contractor) of steel pipe in the wellbore to provide zonal isolation and wellbore stability, so that the well can be drilled safely to deeper targets. Wells tend to be drilled in a telescopic process, with each string of casing cemented inside the last string until the top of the reservoir is reached.

Figure 8: Onshore drilling showing secondary recovery



Source: UBS

While the drilling rig contains all the equipment necessary to drill wells, there is still a considerable range of equipment and services that are provided by other vendors aside from the drilling contractor. There are consumables, such as **drill bits, drilling fluids (muds), casing, and cement** that are required for the drilling process. There are also specialist services that are provided by service companies to assist in the drilling and completion of the well, and are some of the most value-added services provided in the drilling process, utilising some of the most advanced and specialized technology in industry:

- **Directional drilling** – deviating the path of the wellbore away from the vertical plane using MWD/LWD (measurement while drilling; logging while drilling), drilling motors and other steering tools.

At the wellsite, there will be a number of additional service contractors and consumable vendors, whose products are critical to the drilling/completing process

- **Cementing** – pumping cement into the wellbore to secure the casing in the well and provide zonal isolation and structural support.
- **Logging** – using specialized tools containing sources and sensors that provide important information about the rock and fluid properties of the well.
- **Perforating** – using specialized tools to blow open holes in the casing to provide pathways for the hydrocarbons to flow into the wellbore.
- **Completion equipment** – the ‘jewellery’ in the bottom of the wellbore that provides flow assistance and control.

As the technology for drilling wells has evolved, so has the complexity with which wells are drilled. Wells are no longer only drilled along a vertical axis; it is now very common, particularly offshore, but increasingly onshore, for wells to be drilled directionally or even horizontally through productive zones. Technologies such as those referenced above (MWD/LWD, rotary steerable systems) allow wells to be drilled along very precise pathways and steered directly to a pay zone or multiple pay zones that can be many miles away from the location of the rig. Wells are also increasingly completed with multiple drain holes like the roots of a tree to increase the efficiency with which a reservoir can be drained and to reduce the cost of developing a reservoir.

Once a well is drilled through the prospective **reservoir**, the operator will analyze the reservoir rock and typically perform a test to determine the potential flow rate of the well. The flow rate is the speed at which hydrocarbons flow through the wellbore to the surface and will depend on the porosity and permeability of the reservoir rock, the reservoir pressure and the viscosity of the oil, and is a crucial determinant of field economics. Flow rates are measured in barrels of oil per day (bpd) or millions of cubic feet per day (MMCF/d).

When the drill bit encounters the reservoir, the underground pressure forces the oil or gas upwards into the borehole

The completion process

Once a well has been determined to have enough recoverable reserves and sufficient flow rate to be commercial, the operator will decide what type of completion is most suitable for the well, cased hole or open hole and what type of completion equipment to install.

In a cased hole completion, another string of casing or ‘liner’ will be cemented into the well bore. The operator will then turn to the perforating and completion contractors to **perforate** (use explosive charges to blow holes through the liner and open pathways from the reservoir) and then install the completion equipment, which will include **packers** (mechanisms to seal the perforated area from the rest of the wellbore), **flow control** equipment, and perhaps **sand control** equipment.

In an open hole completion, the natural rock will be left exposed and certain production equipment will be installed below the last string of casing to help control the flow of hydrocarbons and sand into the wellbore. In most instances, the operator will also have a string of production tubing installed inside the

casing and connected to the production equipment. Production tubing becomes the conduit for reservoir fluids out of the well.

Well stimulation

Another increasingly important service during the well completion phase is well stimulation. Well stimulation is used almost universally on natural gas wells and increasingly on oil wells. Stimulation services are typically provided by the pressure pumping contractor (similar to cementing) and involve pumping fluids at high pressure down into the wellbore to help stimulate a higher flow rate of production from the well. One of the main methods of stimulation is **fracturing**. Fracturing involves the pumping of fluids that contain **proppants** such as sand or ceramic beads into the well. The force of the fluid into the well fractures the rock creating wider pathways for the hydrocarbons to exit the reservoir. After the fractures are formed and the pumping pressure is reduced, the fracturing fluid returns to surface. However, the proppant remains lodged in the fractures to hold these newly formed pathways open.

An emerging feature of well completions is the increasing presence of measurement and remote control equipment or '**smart wells**'. These types of wells provide the operator with real-time information on the downhole conditions in each production zone, such as flow rate, oil/gas/water mix, temperature, and pressure. Using this information, the operator can then remotely control the downhole and surface production equipment to optimize the productivity of each well from a central office location.

In the instances when operators employ such sophisticated drilling and completion equipment to develop a field, the per well cost of drilling and completing these highly sophisticated wells will significantly exceed that of a conventional vertical well. However, the number of wells required to develop the field is almost always reduced, as is the footprint and size of the facility needed to develop the field. This is very important in an offshore or environmentally sensitive location, as the cost of the production facility can be many times the cost of the actual wells. In addition, much of the new production and monitoring equipment should enable operators to increase recovery rates as well as improve the NPVs of their reservoirs.

The final phase of the well completion process is the installation of the surface or subsea flow control equipment represented by the **wellhead** and **christmas tree**. These devices sit on top of the wellbore and comprise a series of valves and other flow control devices that are joined together to control the flow of hydrocarbons from the well and divert these hydrocarbons to the processing and pipeline systems.

The development process

Once hydrocarbons have been found in economic quantities, the next stage is the drilling of appraisal and development wells, which, as noted above, are drilled in a similar manner to exploration wells, except they are drilled to further assess the commerciality of the discovery, and to actually produce from the target reservoir zones. The drilling of the development wells will often be conducted in conjunction with, or shortly after the building of infrastructure to support the

Another increasingly important service during the well completion phase is well stimulation

Once hydrocarbon reserves are found, production and export infrastructure need to be built and installed

wells, aggregate the production, provide initial separation and processing of the produced fluids, and connect to the transmission infrastructure that carries the product to market.

When oil and gas starts to flow, output is controlled at the surface of the well by the christmas trees and diverted into the production infrastructure that has been built to support the draining of the reservoir. Onshore infrastructure tends to be less complex (and much cheaper) than offshore infrastructure. Barriers to entry are low, as are the capital requirements and hence, the margins. Offshore field infrastructure traditionally consists of an offshore platform with wells connected via **risers** (vertical pipes) to **production trees** (dry trees) on the platform. Initial processing involving the separation of the water, oil and gas produced, is conducted on the platform. The oil and gas is usually exported via a pipeline, though the gas is often re-injected into the reservoir.

Increasingly the traditional platform is being supplanted by **subsea wells** and **floating production** equipment. Subsea wells have the production trees on the sea floor (wet tree) and are either connected to a remote platform, or to a floating production vessel. This solution is used in shallow water for marginal fields (where the economics do not permit a platform for that single field), or for deep water where platforms are no longer technically or commercially feasible. A technology that is currently being developed would also permit processing to be carried out on the sea floor, permitting the oil and gas to be piped to distant facilities.

The natural reservoir pressure forcing the oil to the surface is known as the **primary** or natural **drive**, and typically recovers 10-40% of the oil and up to 75% of the gas. When the reservoir pressure is insufficient to force the oil to the surface, or when the pressure subsides as the field is depleted, various methods are employed to boost the flow rates. **Secondary recovery** methods include the injection of gas into the bottom of the production well to lighten the wellstream (**gas-lift**) or installing surface-mounted pumps above the wells (the well-known 'nodding donkeys'), or submersible pumps in the bottom of the well. Also common is the injection of water into the reservoir (**water injection**) or **gas injection**, both of which are designed to maintain reservoir pressure and hence, flow rates. **Tertiary recovery**, also known as **enhanced oil recovery (EOR)**, methods include injecting carbon dioxide, steam, or surfactants into the reservoir.

The **recovery factor** is the percentage of hydrocarbons in the reservoir, which can be recovered commercially. The recovery factor depends on the nature of the reservoir and the natural pressure. This is supplemented in various ways by enhanced oil recovery techniques.

At the wellhead sand, water and impurities are removed, particularly carbon dioxide and sulphur in the case of gas. Where the oil reserve has **associated gas**, it must be removed. This can then either be used for fuel at the wellhead, re-injected, sold or flared. For environmental reasons flaring is undesirable, and while it is still permitted in some countries, there is increasing pressure in these

Development solutions are changing with the advent of new lower cost technologies

The natural underground pressure forcing the oil to the surface is known as the primary, or natural drive

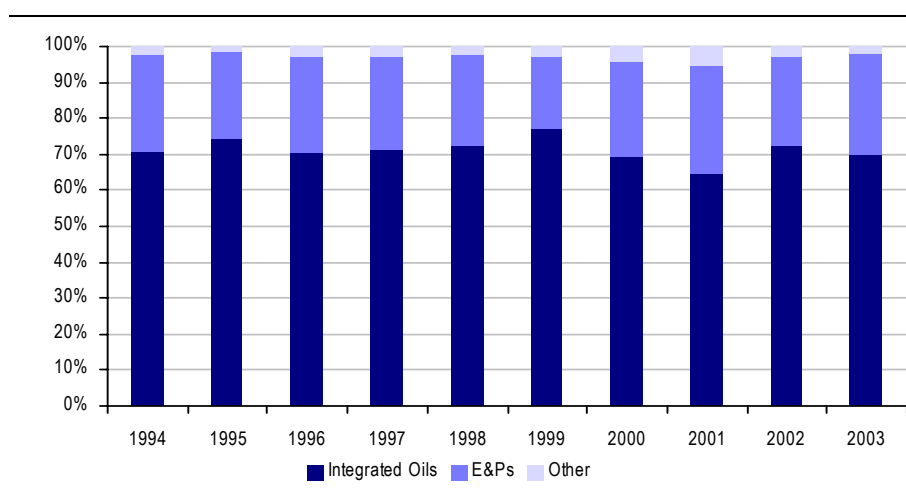
The recovery factor is the percentage of hydrocarbons in the reservoir, which can be recovered commercially

areas to stop flaring gas and to turn it into a productive asset through the development of liquified natural gas (LNG) or gas-to-liquids (GTL) projects.

The oil service industry

The oil service industry is critical to the process of finding and developing oil and gas fields. This industry can be described as a derived demand business in that it does not rely on or sell directly to consumers, but it derives its revenues through the activities of other companies whose revenues and profits are more closely related to the behaviour and needs of consumers. The oil service industry's revenue stream is essentially the capital and exploratory spending of integrated, independent and national oil companies (see Chart 27). Of these three main groups of companies, integrated oils represent the largest piece of the pie. True spending information on national oil companies (NOCs) is not readily available, since many NOCs do not publicly disclose financial information.

Chart 27: Upstream spending by customer segment



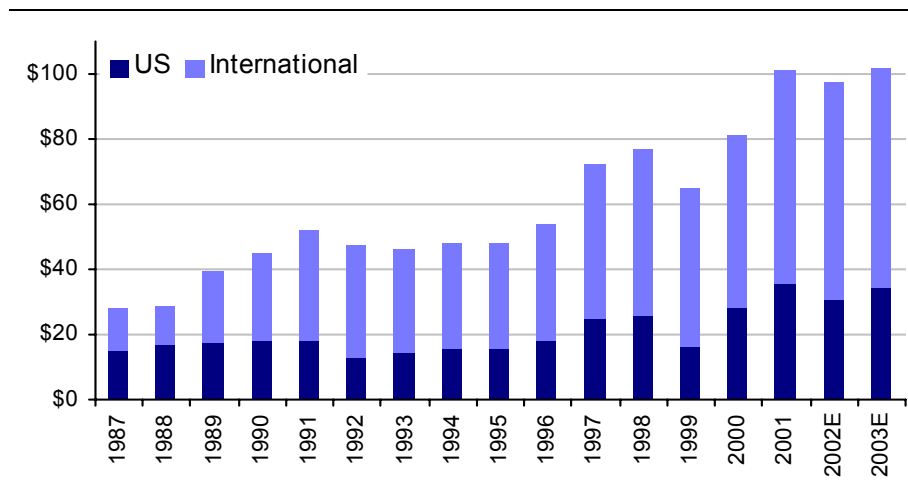
Source: UBS

In periods of rising capital investment in exploration and production, drilling activity, seismic activity, workover and construction activity will all usually rise, causing an increase in equipment and manufacturing utilisation. Many of the businesses in the segment have a high degree of fixed costs; therefore higher utilisation can result in better fixed cost coverage and the ability to raise prices, both of which benefit margins.

Upstream capital spending tends to be driven by several factors including: current and estimated hydrocarbon prices; oil and gas demand expectations; upstream cash flow; and reservoir depletion rates. Over the past fifteen years, there has been a secular trend towards higher investment in upstream infrastructure, particularly relative to the growth in oil and gas production. The following charts show upstream capital spending trends for the top 200-plus exploration and production companies around the world (excluding most national oil companies) for the past fifteen years, as well as the capital spending per boe of production. As can be seen, the current level of capital investment is at an all-time high, but the capital intensity of the industry has also grown substantially over time. Given the diminishing size of new discoveries and the

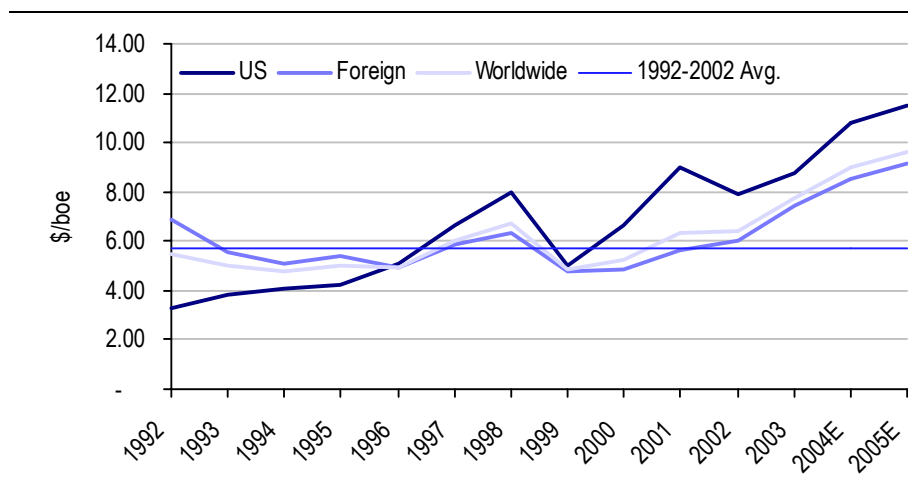
rising depletion rates in existing fields, these trends are likely to remain in place for the foreseeable future.

Chart 28: Upstream capital spending



Source: John S. Herold, Arthur Andersen, UBS estimates

Chart 29: Upstream capex/boe



Source: John S. Herold, Arthur Andersen, UBS estimates

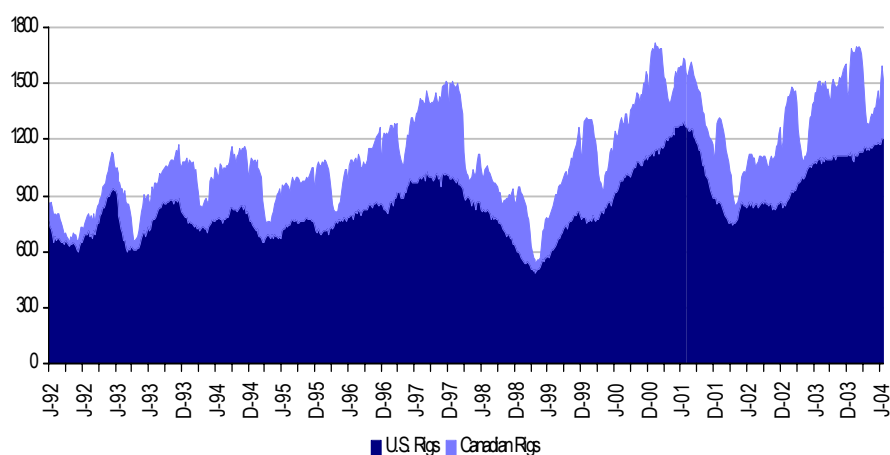
Activity indicators

There are many different indicators that either track various portions of the oil service industry or provide insight into the health of the business. As noted previously, perhaps the most important indicator is upstream capital spending. However, the problem with capital spending information is that it does not come out on a timely basis, and while nearly all E&P companies announce their annual spending plans, few companies actually stick to those plans as the year unfolds.

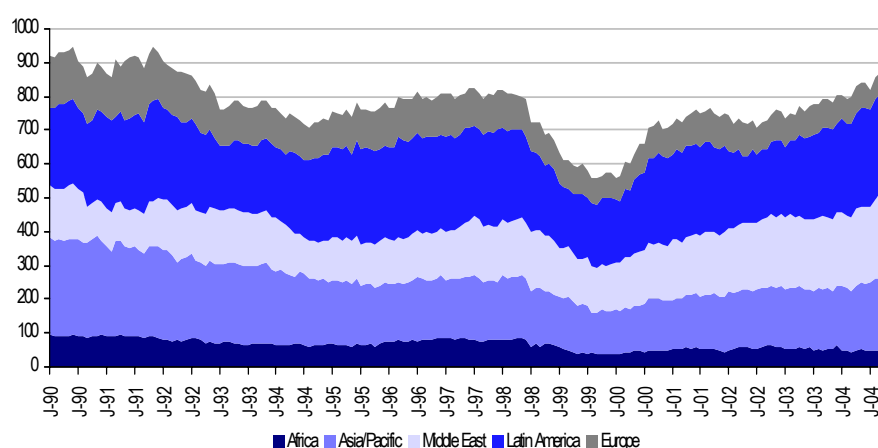
Therefore, investors should look to other indicators to provide more of a real-time picture of the demand for oilfield services and equipment. The most used indicator of industrial activity in the sector is the **Rig Count**. There are a

number of different rig counts, but the most commonly used rig count is the Baker Hughes (BHI) Rig Count. The Baker Hughes rig count measures on a weekly (North America) and monthly (rest of world) basis, the number of rigs that are actually drilling at any given point in time. The BHI count does not include rigs as active unless they are actually making holes. Therefore, if a rig is running casing or if wireline logs are being run, then Baker Hughes does not count the rig as active, even though activity is still being performed at the wellsite by a variety of contractors. While this tends to undercount the number of rigs working or under contract at any given point in time, it is still a very representative measure of industry activity and trends. There are other rig counts from companies like Smith International and industry groups like the Canadian Association of Oilwell Drilling Contractors that use a broader definition of what constitutes an active rig and these measures are also quite useful. However, other than ODS-Petrodata's weekly and monthly data on offshore rig utilisation none of these other counts seems to have wide traction among industry players, analysts or investors.

Chart 30: BHI North America rig count – weekly



Source: Baker Hughes Inc.

Chart 31: BHI International rig count – monthly

Source: Baker Hughes Inc.

The rig count is reported in varying levels of detail including state by state, country by country, rigs drilling for oil versus rigs drilling for gas, onshore versus offshore, by targeted well depth, and rigs drilling vertical wells versus directional or horizontal wells. Analysis of each of these subcategories can provide clues regarding market conditions for a wide variety of oilfield products and services.

Beyond the rig count, there are a number of other indicators that provide insight into the business. Some of these include macro factors, such as oil and gas supply and demand, inventories, futures prices, field development schedules, depletion rates, weather, tax policy, and geopolitical factors. On a more micro basis, some of the key indicators are: lease sale/land sale statistics, seismic crew counts, new field discoveries and discovery success rates, drilling permit/plans filings, workover rig counts, offshore supply boat demand and utilisation, well completion data, rig day rates, and information on drilling costs.

A heterogeneous business

As demonstrated in the preceding section, the exploration and development process is a complex process that involves a variety of specialised skill sets, equipment and technology. It is also largely performed by outside contractors as opposed to the oil companies that actually own the acreage or hydrocarbon bearing assets. Through the consolidation and subsequent downsizing of the producing companies, oil companies have significantly cut back on research and development and shied away from owning service and in some instances production assets as well. For an oil company, it is often an inefficient use of its capital to own drilling rigs or other service/manufacturing assets, since it cannot typically generate a high enough level of utilisation to support the costs of ownership. By contrast, service companies that work for multiple customers across multiple geographical zones are better positioned to maximise asset utilisation and capitalise on the development of new technologies. Therefore, service companies play a vital role in finding and developing oil and gas fields. As noted, with the declining investment in R&D by the oil companies, it has increasingly become the domain of service companies to carry the load in terms of research and new product development. While the service industry has not

done a great job of capitalising on the increased value that its products and services bring to the process in the past, there are signs that this is changing.

While the ultimate role of any service company is to assist in the finding, development, and production of oil and gas, the industry is hardly homogenous in terms of the range of services provided or business models followed. There are companies that provide cutting edge technologies for prospect and reservoir analysis, and others that provide specialised drilling and well completion or production equipment or services to efficiently locate and produce hydrocarbons from a well. There are still others that are essentially asset players, owning a range of assets such as drilling rigs, supply boats, and construction vessels/equipment. Each of these companies is vital to the process, but each contributes value at varying levels. Table 2 shows the main array of services and equipment that make up the oil services industry, along with the key players in each service, the size of the market, the relative degree of consolidation in the sector, and the phase of the oilfield in which these services/equipment are performed/used.

Oil companies own the reservoirs, but oil service companies are critical in finding, developing and producing them

Table 2: Oil service industry product line, structure and timing matrix

PRODUCT LINES	The Players (largest to smallest)	Top 3 Share	Tot Yearly Rev (\$B)	When Products/Svcs Used		
				Expl	Dev	Prod
Artificial Lift	WFT, BHI, SLB, WGL, LUFK, DOV, Harbison Fischer, RBN	62%	\$3.3		X	X
Installation of Casing and Tubing	WFT, Frank's, BJS, Allis-Chalmers	85%	\$0.7	X	X	
Casing Hardware & Cementing Products	WFT, HAL, Davis-Lynch, Frank's	80%	\$0.3	X	X	
Coiled Tubing	SLB, BJS, HAL, RES, SPN, TCW.TO, Trailblazer, Sangel, CalFrac, WFT, PDE, Technicoil, PDS, ESI.TO	63%	\$1.2		X	X
Compression Rental/Services	HC, UCO, Compressor, J-W, Enerflex, TTI, Henry Production	79%	\$1.3		X	X
Completion Equipment & Services	BHI, HAL, SLB, WFT, BJS, SII, TAM, Expro, SPN, PDS	74%	\$3.6	X	X	X
Directional Drilling (MWD and/or DD)	SLB, HAL, BHI, Scientific, WFT, PDS, WHES, Phoenix, Cathedral, COSL, NBR	80%	\$3.0	X	X	
Downhole Drilling Tools	NOI, WFT, NQL, Sondex, RBN, SII, Gotco, WZL.TO	52%	\$0.5	X	X	
Drill Bits	BHI, SII, GRP, HAL, Varel, Rock Bit Ind., PDS, WFT	79%	\$1.7	X	X	
Drilling/Completion Fluids	SII, HAL, BHI, NR, TTI, BJS, PTEN	74%	\$4.4	X	X	X
Floating Production Systems/Equipment	SBM, PGO, Bluewater, Prosafe Productions, Modec, OII, Bonheur, Maersk, Saipem	67%	\$1.6		X	X
Seismic Equipment/Services	SLB, CGG, PGO, VTS, HAL, IO, SEI, TGS-NOPEC, Paradigm, Trace, DWSN, Grant, COSL, OYOG, OMNI, MIND	58%	\$5.6	X	X	X
Inspection and Coating	VRC, SII, ShawCor, Patterson Tubular	84%	\$0.5	X	X	X
Land Rigs	NBR, PTEN, PDS, ESI, HP, PDE, GW, UNT, SLB, Abbot Group, PKD, PDC, Saipem, Egyptian Drilling, KEG, RDC	36%	\$8.0	X	X	
Logging while Drilling (LWD)	SLB, HAL, BHI, WHES, Geolink, PDS, Scientific	86%	\$1.0	X	X	
Mud Logging	BHI, Geoservices, HAL, NBR, Datalog,	66%	\$0.4	X	X	
Offshore Maintenance and Operations	Kvaerner, HAL, BKR, SPN, WGL, Island Operating, SLB, Danos & Curole, TORC, OLOG, GLBL, RES	59%	\$2.9			X
Offshore/Rig Infrastructure Construction	TKP, Saipem, MDR, HAL, SOSA, Kvaerner, Subsea 7, SBM, GLBL, CDIS, OII, GIF, FTI, HOFF, RDC, UFAB, TORC	39%	\$14.4		X	X
Casing, Tubing, Drill Pipe, etc.	Tenaris, MVK, V&M Tubes, LSS, GRP, Sumitomo Pipe and Tube, US Steel, NSS, North Star Tubular, HYDL, Hunting, WFT, SII	42%	\$7.5	X	X	X
Offshore Rigs	RIG, GSF, PDE, NE, DO, ESV, RDC, Smedvig, Dolphin, Maersk, NBR, ProSafe, Saipem, Abbot, COSL, ATW, PKD, HP	35%	\$12.8	X	X	
Petroleum Aviation	CHC, OLOG, PHEL, RDC, Heli-Union, Gulf Helicopters	70%	\$2.0	X	X	X
Pressure Pumping	HAL, SLB, BJS, TCW.TO, CalFrac, RES, PDE, BHI, Sangel, American Energy, WFT, PTEN, Basic, COSL	82%	\$9.0	X	X	X
Production Testing	SLB, Power Well Svc, Expro, TTI, Geoservices, Integrated Production, FESCO, ESI.TO	70%	\$0.7		X	X
Rental & Fishing Services	WFT, SII, BHI, OIS, SPN, TESCO, NR, PDS, PKD, KEG, NBR, RES, ESI.TO, WHQ	48%	\$2.7	X	X	X
Production/Specialty Chemicals	BHI, Nalco, Champion, SII, BJS	78%	\$1.9			X
Rig Equipment Manufacturers	NOI, VRC, CAM, OIS, Kvaerner, Vetco, HYDL, Pason Sys, Abbot, Wirth, WFT, GDI, RDC	65%	\$3.0	X	X	X
Solids Control	SII, VRC, Oiltools, NR, Derrick, Peak Energy	79%	\$0.9	X	X	
Surface/Subsea Production Equipment	FTI, CAM, TKP, Kvaerner, Vetco, DRQ, OII, WGL, Wellstream, HAL	57%	\$5.3	X	X	
Supply Vessels (Marine Transportation)	TDW, CKH, SBLK, GMRK, Maersk, TMAR, COSL	47%	\$2.4	X	X	X
Underbalanced Drilling	WFT, SLB, PDS, BJS, HAL, Smedvig, Allis-Chalmers	73%	\$0.8		X	X
Wireline & Production Logging	SLB, BHI, HAL, PDS, Expro, Integrated Prod'n, WHQ, WGL, SPN, WFT, BWWL.OB, Geoservices, COSL, ESI.TO	76%	\$4.8	X	X	X
Workover Rigs/Well Servicing	KEG, NBR, PDS, Basic Energy, ESI.TO	46%	\$2.0			X

Source: UBS estimates

Oil service performance metrics

Since oil service companies are a heterogeneous mix of businesses and do not find, develop or produce hydrocarbons, the performance metrics for these companies differ from those applicable to integrated oils or exploration and production companies. We tend to focus on more generic methodologies for benchmarking performance by comparing companies on the basis of returns, profitability, growth, balance sheet, capital intensity measures, and efficiency measures (listed in order of importance). In our opinion, there is no 'go to' or 'catch-all' metric or ratio that allows investors to benchmark one company's financial performance or future potential versus another. However, we have found that a thorough financial analysis using a series of ratios that fall into the categories listed above can be of significant value for investors that are trying to distinguish between the companies that are likely to outperform and underperform in the long term. This type of analysis also provides a more unbiased, objective approach to evaluating the quality of a company's business mix and its management's performance.

Gas processing and marketing

Many companies are involved not only in the production of natural gas, but also in the **processing** and **marketing** of both **natural gas** and **natural gas liquids**. In this section we explain the processes involved.

In the United States, 19 tcf (trillion cubic feet) of natural gas is gathered, treated, conditioned, and delivered annually, the equivalent of more than three billion barrels of crude oil.

The process begins at the wellhead with the production of raw natural gas. The composition of natural gas varies widely, depending on the field, reservoir, or formation from which it is produced. Before processing, gas contains pure natural gas (**methane**), **NGLs** (including ethane, butane, propane, isobutane, and natural gasoline), and a number of **impurities** (e.g. hydrogen sulphide, carbon dioxide and water).

Gas processors describe gas as ‘**wet**’ (rich in NGLs), or ‘**dry**’ (minimal NGLs) depending on its NGL content. When produced, natural gas is rarely suitable for pipeline transportation or commercial use. Hence, the gas must be processed. There are no strict industry-wide specifications, as each pipeline imposes its own standards depending on its system requirements.

Processing in the gas plant involves two basic operations – extraction of the NGLs from the gas stream and fractionation of the NGLs into their separate components. Additional processing is usually required to treat and condition both the natural gas and the NGLs.

Depending on the liquid content of the gas, processing can be as simple as drying the gas by passing it through a fixed bed of a desiccant material or it can be much more complex. The two most important extraction processes are the **absorption** and **cryogenic** processes. Together, they account for 90% of all NGL production from natural gas.

At this point, the pure methane is of ‘pipeline quality’ and enters the long-distance transmission network. The NGLs are fractionated and separated into their various components and are eventually used as liquefied petroleum gases, gasoline blending components, raw materials for basic petrochemicals and for heating purposes.

The process

Absorption process

The basic step in the **absorption** process is to remove NGL components from the natural gas by contact with an absorbing oil. Approximately 85% of the propane and essentially all of the heavier NGLs can be absorbed in the oil. The lighter fractions (methane, ethane, and some of the propane) are not recovered in the absorbing oil and pass through the absorber tower as pipeline-quality natural gas.

Many companies process and market natural gas and natural gas liquids

More than 19tcf of gas is treated annually

When produced, natural gas is rarely suitable for pipeline transportation

Processing involves separating the gas into its constituent parts

Absorption removes NGLs from natural gas

Absorbed liquids are distilled from the absorber oil by heating the mixture to a temperature above the boiling point of the NGLs but below that of the absorber oil.

Cryogenic process

In recent years, **ethane** has become increasingly desirable as a petrochemical feedstock. This has resulted in the construction of many plants that recover ethane, at temperatures as low as minus 150°F. By cooling the liquid-laden gas to extremely low temperatures, 90-95% of the ethane and all of the propane and heavier liquids drop out of the gas.

The cryogenic process recovers ethane at cold temperatures

Fractionation

Processing breaks the wet gas into two components – marketable **methane** and a mixture of liquids. The mixed liquid then needs to be fractionated into its separate **NGL components**. The fractionation system might be part of the gas processing plant or the liquids might need to be transported to a central fractionation facility.

Fractionation separates NGL components

The mixed NGL stream is fractionated into separate components by controlling the temperature of the stream in a fractionator, taking advantage of the difference in boiling points of the separate products. Fractionators are usually named for the overhead or top product (e.g. a de-ethaniser implies that the top product is ethane).

Other routine gas processing

Both natural gas and NGLs may require additional treating or processing, either before or after the extraction of liquids. The most common treatment of natural gas is to remove excess water vapour, which is necessary to prevent its freezing in pipeline transmission systems.

Additional treatment of both natural gas and NGLs is usually required to remove **hydrogen sulphide** (it is corrosive) and carbon dioxide (it is hazardous to breathe). This process is known in the industry as ‘sweetening’.

Other specialised gas processing

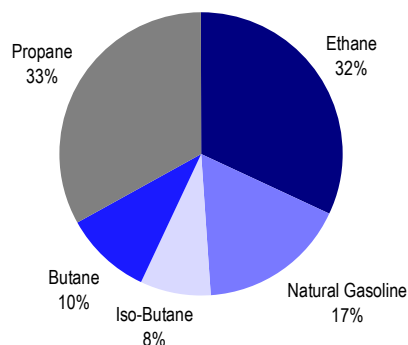
Depending on gas composition and other factors, the gas processing function may also include additional processing such as:

- Carbon dioxide removal and subsequent use for enhanced oil recovery
- Helium recovery for commercial sale
- Nitrogen removal to increase heating value of gas
- Liquefaction of the total gas stream to produce liquefied natural gas (LNG)

Natural gas liquids

A typical barrel of NGLs contains natural gasoline, isobutane, propane, butane, and ethane.

Chart 32: Natural gas liquids – typical contents



Source: Department of Energy

Ethane

Ethane only exists as a liquid under very high pressures or at extremely low temperatures. It is recovered and transported in either the liquid or gaseous state, principally for use as feedstock to produce ethylene, the most important basic petrochemical produced today.

Ethylene is the most important basic petrochemical

Propane

Propane is recovered and handled as a liquid. Its principal uses are as feedstock for the production of ethylene and propylene (for products such as plastic bags), and as liquefied petroleum gas (LPG) for homes and businesses.

Propane is used as a feedstock for the products of ethylene and propylene and as LPG

Propane is used in homes and businesses for heating, cooling, cooking, and refrigeration, as well as a fuel for barbecues. In addition, **LPG** can be used to fuel vehicles and irrigation pumps.

Natural gasoline

This is a mixture of **pentanes** and heavier hydrocarbons, with small amounts of **butane** and **isobutane**. It is recovered as a liquid, principally for use as a gasoline-blending component.

Natural gasoline is used as a blending component in gasoline

Butane

Butane is recovered and handled as a liquid under moderate pressure. Its principal uses are to provide needed volatility to gasoline, as LP-gas fuel, either alone or in mixtures with propane, and as a feedstock for the manufacture of ethylene and butadiene, a key ingredient of synthetic rubber. Butane molecules can also be rearranged to produce isobutene, a process known as isomerisation.

Butane is used to provide volatility to gasoline, as LPG and as a feedstock

Isobutane

This is the chemical isomer of butane and is fractionated from 'field grade' butanes or derived by isomerisation of normal butane and produced as a separate product. It is principally used for the manufacture of alkylate, a vital ingredient in high-octane motor gasoline. It has become an increasingly important product for production of methyl tertiary butyl ether (MTBE), which is used as a high-octane oxygenate required in reformulated motor gasoline.

Isobutane is principally used for the manufacture of alkylate

Demand for NGLs

Approximately 85% of the NGLs produced in the United States are consumed in three major areas: (1) petrochemical feedstocks; (2) motor gasoline manufacture; and (3) residential and commercial heating fuels. The remainder are used in a wide variety of applications, including engine fuels, industrial fuels, utility peak shaving, crop drying, and other agricultural and process fuel applications.

85% of NGLs produced in the US are used in three areas: petrochemical feedstocks, gasoline manufacture and heating fuels

Currently, NGLs provide about 70% of the feedstocks for production of ethylene, the most important basic petrochemical produced. In addition, approximately 10% of US motor gasoline needs are derived from NGLs.

Pricing: the ideal NGL market

For gas processors, the ideal market is one of low natural gas prices and high crude oil prices, as this situation maximises NGL margins. NGLs, which are sold in barrel units, sell on average at 70% of the price of WTI crude. Thus, if crude prices are increasing, NGL prices will typically rise as well.

The ideal NGL market is one of low gas prices and high crude oil prices

Liquefied natural gas (LNG)

Natural gas is the world's third largest, and fastest growing, source of primary energy as environmental pressures and technical advances provide strong incentives to choose gas, particularly for power generation. Depleting domestic supplies and growing regional demand and supply imbalances are resulting in this demand growth requiring additional international trade flows. As recently as 2001 approximately 85% of world gas production was consumed locally, however today more than 23% of supplies are traded across international borders, primarily through either pipelines (volumes up 46% since 1995) or via LNG transportation (up 62% over the same period).

Natural gas is the world's third largest and fastest growing source of primary energy

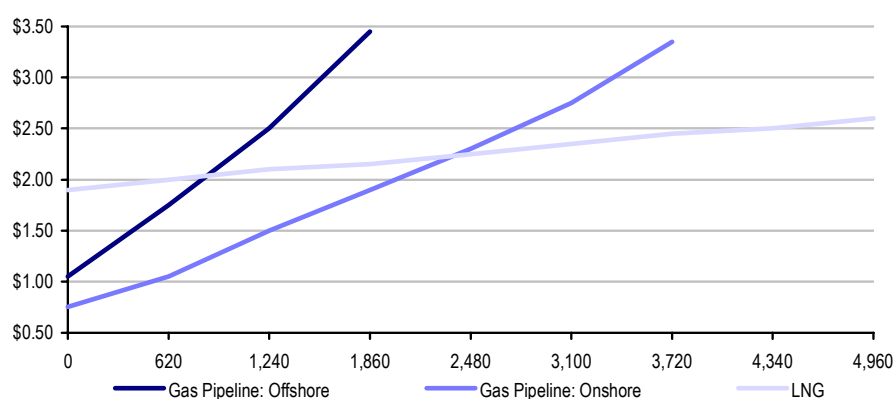
Overview

As a result of the exploitation of local reserves, many gas fields are located great distances from the major gas consuming markets and therefore transportation is becoming an important issue in the gas market. Natural gas can be transported from source to market by pipeline or alternatively the gas can be cooled to such a degree (specifically -260°F) that it condenses to form a liquid (reducing the gas to one six hundredth of its gaseous volume) enabling it to be shipped via tanker. Each tanker can transport up to 150,000 cubic meters of LNG, providing over three billion standard cubic feet of natural gas (equivalent to almost 600,000 barrels of oil).

Many gas fields are located great distances from consuming markets and therefore transportation is important

Due to the alternate cost structures of the two methods of transportation, the point at which LNG becomes economically preferable to pipelines occurs at a distance of approximately 1,500 miles for offshore pipelines or 3,500 miles for onshore pipelines as illustrated below. Additionally, however, LNG involves few of the political, geographical and sometimes environmental considerations that can hamper pipeline developments across international borders, making this decision not merely a financial one.

Chart 33: Transportation cost



Source: Institute of Gas Technology

The process

There are four main stages in converting gas into LNG. Firstly impurities such as carbon dioxide and sulphur are removed, then water is removed, which would turn to ice during the liquefaction process. Thirdly, the heavier hydrocarbon molecules are removed, leaving mainly methane and ethane, with the resultant

gas then progressively cooled until it becomes liquid at atmospheric pressure. The units involved in this process are known collectively as a **train**. All existing LNG plants consist of more than one train to facilitate the phasing of repairs and maintenance. Each train can cost over \$1bn (excluding ships). The LNG is then stored in insulated tanks before being loaded into cryogenic tankers for shipment. Before use, it is regasified at a receiving terminal and then sold on to the end consumer.

LNG projects are highly capital intensive. Construction and start-up times are usually around four years and it is common practice to conclude at least 20-year supply contracts in order to reduce risk and to justify the finance required to acquire or build the necessary infrastructure.

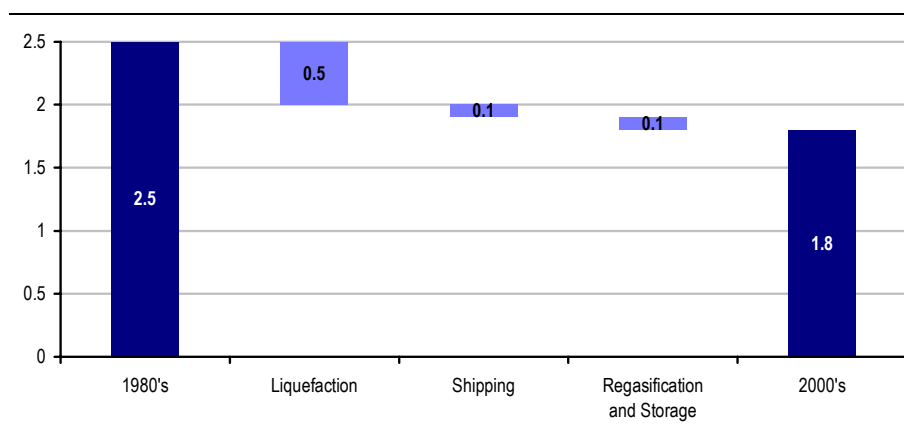
LNG projects are highly capital intensive

The LNG market

The first commercial LNG plant was built to supply LNG from Algeria to the UK, with the first shipments made in 1964. Today, around 6% of global gas consumption is transported via LNG, accounting for 26% of the international gas trade. This establishment of LNG as a viable method of gas transportation has been made possible through significant recent reductions in the costs of liquefying, transporting and regasifying LNG (as shown in the graph below) resulting in LNG volumes growing 35% in the five years from 1997 to 2002.

Today, around 6% of global gas consumption is transported via LNG

Chart 34: Typical LNG cost progression (\$/mmbtu)



Source: El Paso

These developments have reduced the friction of distance in the global LNG market, encouraging a proliferation of trading routes and escalations in volumes traded. In 2003 127.4 million tons of LNG were shipped, equivalent to 1,105 million barrels of oil, which was up 14% from the previous year.

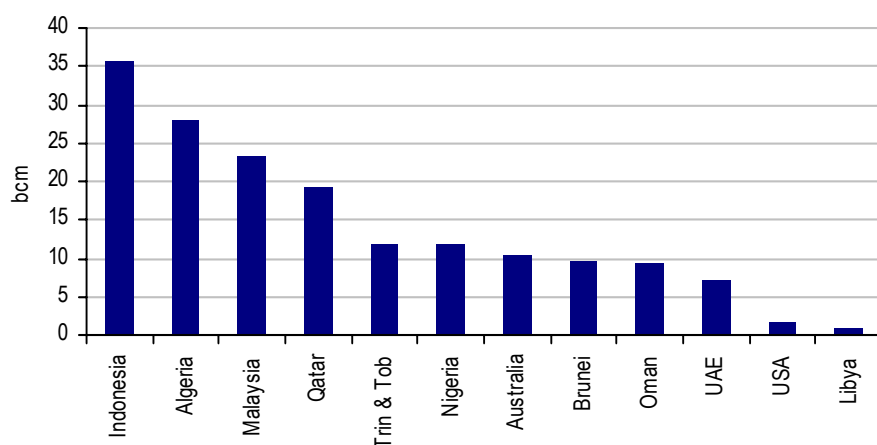
Essentially the Middle East has emerged as a net exporting region, sandwiched between two consuming regions, namely the Asia/Pacific and the Atlantic basins. The Asia/Pacific basin is the more established of the two markets while the Atlantic, although more embryonic, is more fragmented and faster growing as these countries are rapidly expanding regasification capacity.

The Middle East has emerged as a net exporting region, sandwiched between two consuming regions, the Asia/Pacific and the Atlantic basins

Exporters

In 2002 there were 12 LNG exporting nations, with Indonesia accounting for approximately 20% of global exports. In addition to these, many new projects are under construction in Egypt, Russia and Australia, which will serve to further diversify supply.

Chart 35: Global LNG exporters (2003)



Source: BP Statistical Review

Importers

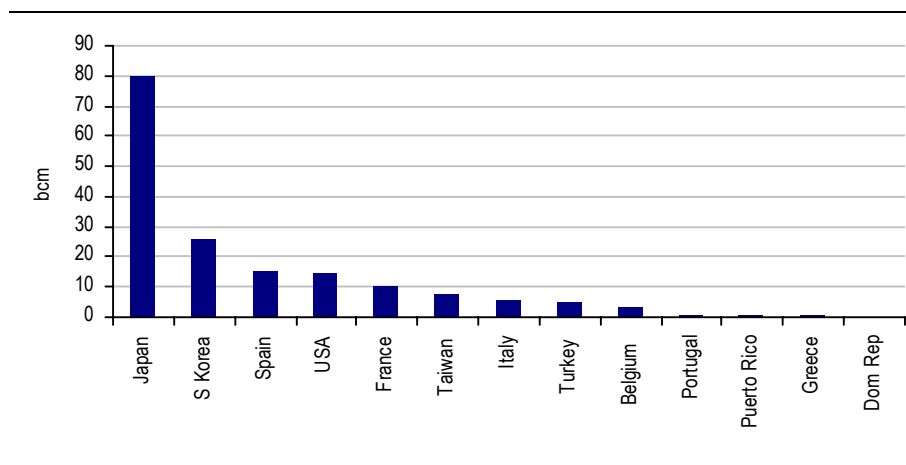
Although the Asia/Pacific basin includes the world's largest LNG exporters, it is still a net importer on account of the huge demand from Japan, Korea and Taiwan. Indeed, Japan alone currently accounts for 48% of global imports, this figure having fallen from 66% in 1990.

Japan's dwindling share of LNG imports is a direct reflection of the growth of the global LNG market and the increasing number of importing nations. One such emerging importing nation is the US which has already seen its LNG imports grow by more than 200% in the last four years and which currently imports 2% (or 229bcf) of its natural gas consumption via LNG each year. This figure is anticipated to more than quadruple by 2010.

The US has seen its LNG imports grow by more than 200% in the last four years

The US is expanding its LNG imports to reduce its reliance on both diminishing domestic reserves and already stretched Canadian pipeline imports (which account for 15% of total US gas consumption). Additionally, LNG exporters have targeted the US market as a result of the recent strength of North American gas prices offering more attractive margins to suppliers.

Other active importers of LNG are France, Spain and Belgium. India started importing LNG this year and the UK is constructing regasification terminals and preparing to become an LNG importer.

Chart 36: Global LNG importers (2003)

Source: BP Statistical Review

LNG trading

Historically, the LNG market has been driven almost entirely by long-term, customized, life of field type inflexible contracts, especially in the Asia/Pacific basin. This lack of contract flexibility was a result of the concentration of demand, the large front-end loaded capital requirements of LNG projects and buyers eager to secure energy supplies.

However, in recent years the distinct trend in both the Atlantic and Asia/Pacific basins has been for these contracts to grow increasingly flexible in terms of volumes and pricing as the market matures and becomes more liquid. This flexibility has resulted in a dramatic increase in short-term contracts and even resulted in the emergence of speculative LNG trading in the spot market. Indeed, spot trading has grown from 1% of LNG market volumes in 1992 to 10% currently and is likely to continue to 20% over the next decade. This improving flexibility, along with the increasing diversity of supply, is enabling the LNG market to respond more efficiently to unforeseen supply disruptions.

As importers in the Asia/Pacific basin rely almost exclusively on LNG for all of their energy requirements, LNG in Asia has historically traded at a premium to the Atlantic, reflecting the less elastic demand curves. The Atlantic however, due to increased competition and greater elasticity of demand, has led the push towards more short-term contracts, with margins under pressure. The emergence of the Middle East as a net exporter between these two consuming markets, and the ability to transport gas longer distances via LNG to exploit pricing irregularities is likely to result in a convergence of prices and margins, potentially leading to a single global LNG market.

Historically, the LNG market has been dominated by long-term, customized, life of field type inflexible contracts

In recent years the distinct trend has been for these contracts to grow increasingly flexible

A single, global LNG market is likely to emerge

GTL (gas-to-liquids) technology

GTL, like LNG, is a method of converting natural gas into liquids for ease of transportation by pipeline, ship, rail or road and so enabling remote natural gas reserves to be monetised. Again like LNG, GTL has environmental support as the liquids produced by GTL offer very attractive ecological characteristics (no sulphur or aromatics) at a time of increasingly stringent demands for cleaner burning fuels and restrictions on the practice of flaring. This, however, is largely where the similarities between these two processes end, as LNG does not alter the chemical make up of the gas, whereas GTL involves the conversion of natural gas into high-quality diesels and basestocks.

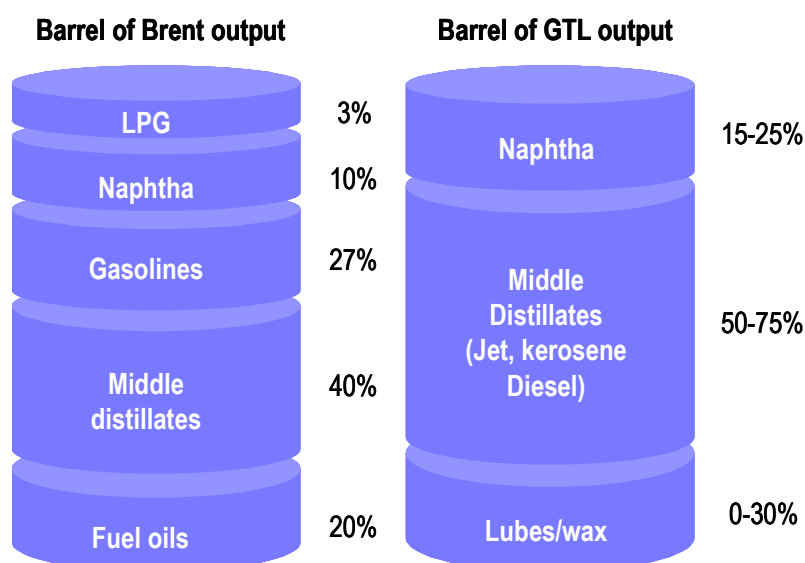
The process

Natural gas is blended with oxygen to create a product known as ‘synthesis gas’ – a mixture of carbon monoxide and hydrogen. It is then heated under extreme pressure and a catalyst (normally cobalt) is added to turn the synthesis gas into waxes and light hydrocarbons. This is known as the Fischer-Tropsch process – after its inventors in the 1920s – and essentially extends the carbon chain lengths. The heated synthesis gas is fed into the bottom of a reactor where it mixes with a slurry of liquid wax and the catalyst. As the gas bubbles upwards through the slurry it diffuses into it, creating more wax. The third stage is effectively a standard cracking of the wax into middle-distillate fuels, mainly diesel and naphtha, which has potential as a fuel for fuel-cell applications due to its sulphur-free properties and its high hydrogen content. Other outputs include quality basestocks which can be used to make improved lubricants, for which demand is growing from automotive manufacturers who are in turn meeting demands to increase fuel efficiency, lower engine emissions and improve reliability.

GTL technology involves the conversion of natural gas to high-quality diesel

Natural gas is blended with oxygen to create a product known as ‘synthesis gas’

Figure 9: Refinery/GTL barrel products split



Source: Petroleum Economist

The cost

In theory this technology requires an oil price of \$19/bbl on a sustainable basis for it to be viable. Below we demonstrate the theoretical costs of the first sizeable project, a joint venture between Sasol & Qatar Petroleum in Qatar.

Table 2: Theoretical costs of Sasol's Qatar project

Costs	\$/bbl	
Natural gas	5.5	(assuming 55c/BTU)
Operating costs	6.0	(assuming no synergies with other projects)
Transport costs	2.0	
Interest costs	5.4	(@ interest of 6.75%)
Total cost	24.0	
Estimated oil price equivalent	19.0	

Source: UBS. Note: this ignores the possible premium the diesel could receive for its low sulphur content

The economics of GTL technology vary for different geographic locations and are affected by many factors, from the size of reserves and construction costs, to the local tax structure and the price received for products. The current focal locations for gas-conversion plants are the Middle East (especially Qatar), West Africa and Australia.

Heavy investment coming

To date, GTL projects are yet to fulfil their potential and have amounted to little more than pilot or small-scale projects, or specialised plants producing high-quality lubricants. Indeed, on account of these start-up costs, a recent survey by consultants, Wood Mackenzie, determined that LNG projects offer a higher net present value than equivalent GTL projects.

However, the abundant supplies of LNG in relation to global demand and the forecast that GTL products (particularly diesel) will play an increasing role in the future are encouraging producers towards GTL as an alternative means of monetising their gas reserves. These GTL projects are further encouraged by both the continued reductions in the up-front expenditure required, and rising oil price expectations. Against this backdrop, GTL projects are being rolled out by several companies which should see global capacity from GTL, currently running at less than 40,000 barrels a day, rise to over 800,000 barrels a day over the next decade, if the planned developments go ahead. The following table shows some of the projects either under construction or already complete.

Many oil companies investing in GTL

If all planned projects go ahead, global GTL output may exceed 800,000 bpd

Table 3: The world's commercial and proposed GTL plants

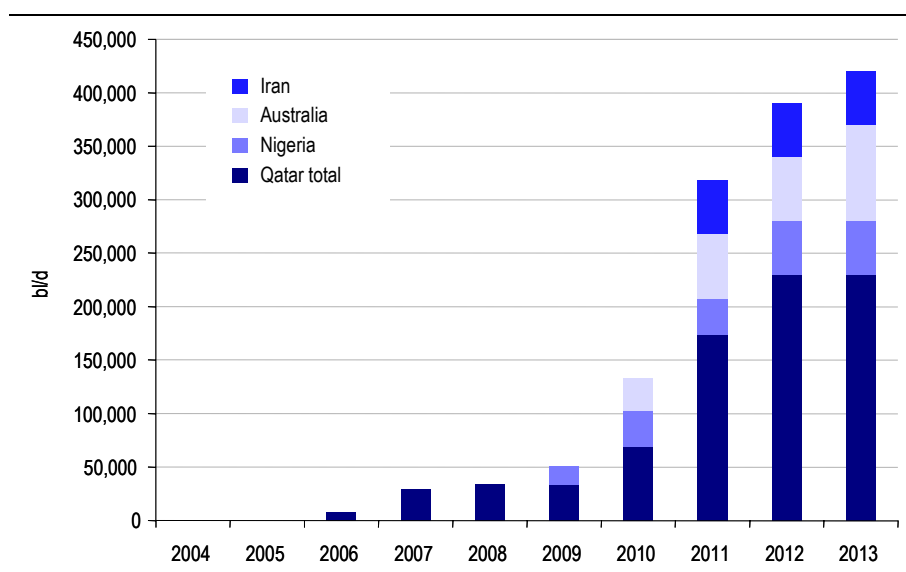
Plant	Company	Capacity (b/d)	Start-up
Mossgas GLT	Petro SA	22,500	1993
Sasolburg	Sasol	2,500	1993
Bintulu	Shell	12,500	1993
Alaska	BP (pilot)	300	2002
USA	Conoco (pilot)	400	2002
Qatar	Sasol / QGPC	34,000	2006
Bolivia	Rentech	10,000	Planning
Nigeria	Canadian Natural	34,000	Planning
Qatar	Shell	140,000	Planning
Qatar	ConocoPhillips	160,000	Planning
Qatar	Rentech	16,000	Planning
Qatar	Syntroleum	90,000	Planning
Qatar	Sasol/Chevron	130,000	Planning
Qatar	Sasol/Chevron	66,000	Planning
Russia	Syntroleum	13,000	Planning
Qatar	ExxonMobil	100,000	Planning

Source: Petroleum Economist 2003, Sasol & UBS

BP estimates that over 10 billion cubic feet of natural gas per day could be put through the GTL process by 2015, creating a million barrels of diesel; however, as yet consumers have not seemed willing to pay a premium for the cleaner products GTL technologies can offer. This demand may ultimately be required to secure the future viability of GTL; alternatively governments may one day stimulate demand through fiscal incentives.

The company leading the way in GTL development is Sasol, with several developments currently planned. Although the company currently has no GTL production, it is forecasting to produce almost 450,000 barrels a day by 2013. The graph below illustrates Sasol's exponential GTL growth potential.

The company leading the way in GTL development is Sasol, with several developments currently planned

Chart 37: Sasol's GTL growth projections

Source: Sasol, UBS

Refining and marketing

Crude oil almost always needs to be processed (**refined**) prior to consumption. The process of refining separates crude oil into useable finished products for transportation, residential and commercial heating, power generation, petrochemical production and asphalt formation. It is refining which gives oil its value. Marketing refers simply to the distribution and sale of refined products, from bulk distribution to retailing. Integrated oil companies tend to report refining and marketing earnings together.

The process of refining separates crude oil into useable finished products

In the past, **refining and marketing**, collectively known as the **downstream**, were seen simply as ‘distribution’ cost centres – a necessary evil in the extended process of monetising abundant crude oil. Although full-cycle returns in the downstream are typically lower than in either exploration and production or petrochemicals, recent developments in process efficiency and general cost-cutting efforts have led to increased profitability among the industry leaders.

Marketing refers to the distribution and sale of refined products

The refining industry is a global, highly cyclical commodity business in which profitability is sensitive to marginal changes in product supply or demand. Marketing, on the other hand, is more regional in nature and earnings are more stable. The volatility of refining and marketing, or ‘downstream’ earnings arises primarily because of the cyclicity of refining margins.

Refining

Refinery configuration

A refinery should be thought of as one large production line: crude oil enters at one end and is subject to a number of processes, which alter its state in a particular way.

A refinery should be thought of as one large production line

Refineries are categorised by **size** and **configuration**. The configuration or level of sophistication refers the extent to which crude oil is processed: is the oil simply distilled (i.e. broken into components), or do further processes and blends result in greater product variety and enhanced product performance? The greater the number of processes, the more sophisticated the refinery.

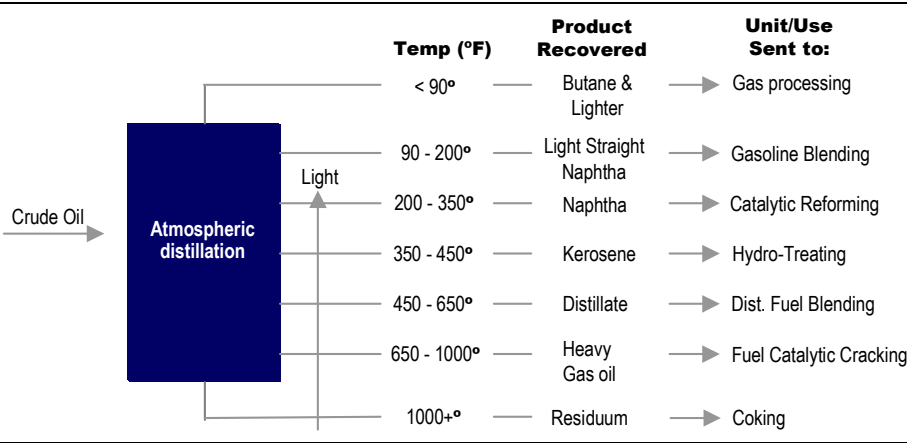
The configuration of a refinery is determined largely by geographical location, i.e. the product demand in the area or in the export destination. Countries at different stages of development have different petroleum product demands. Less developed countries in the early stages of industrialisation require more heavy fuel oils. Developed countries have more advanced technology requiring lighter, more efficient fuel inputs.

The configuration of a refinery is determined largely by geographical location

Refining processes

The basic refining process is illustrated below. Unfortunately, this rarely produces the mix of products required by the market, principally because it is not possible to make **high-octane gasoline** (petrol) from a simple or ‘straight run’ refinery. Instead, a large amount of low-value fuel oil and residue is produced. To produce gasoline in volume it is necessary to break down the heavier hydrocarbon molecules to make the lighter gasoline product.

Chart 38: Crude oil distillation – the first step



Source: UBS

Simple distillation

The core refining process is simple distillation, illustrated in a stylised fashion above. Because crude oil is made up of a mixture of hydrocarbons, this first and basic refining process is aimed at separating the crude oil into its ‘fractions’, the broad categories of its component hydrocarbons. Crude oil is heated and put into a still – a distillation column – and different products boil off and can be recovered at different temperatures. The lighter products – liquid petroleum gases (LPG), naphtha, and so-called straight run gasoline – are recovered at the lowest temperatures. Middle distillates – jet fuel, kerosene, distillates (such as home heating oil and diesel fuel) come next. Finally, the heaviest products (residuum or residual fuel oil) are recovered, sometimes at temperatures over 1,000°F. The simplest refineries stop at this point. Many, however, reprocess the heavier fractions into lighter products to maximise the output of the most desirable products, as shown schematically in the illustration, and as discussed below.

Primary refining units fall into three processing categories: **separation**, **conversion** and **treatment**. The initial stage of a refining run involves the heating and separation of crude oil into its constituent parts. Therefore, once the fractionations of crude oil are **separated**, they are directed to various **conversion** units to be chemically altered through the introduction of heat, pressure, catalysts or hydrogen. The output of these conversion units is then subsequently **treated** or **blended**.

1. Separation

Atmospheric distillation

Distillation is a physical separation process that does not alter the molecular structure of hydrocarbons. Various crude components have different boiling points and can therefore be separated at a number of stages as the temperature of the crude is increased. As crude is gradually heated, the gases (methane, ethane, propane and butane) evaporate first and rise to the top of the distillation column. These are followed by naphtha, which is used in the blending of motor and aviation gasoline and as a petrochemical feedstock. The medium distillates, which have a higher boiling point, are converted to jet fuel, diesel oil and

Primary refining units fall into three processing categories: separation, conversion and treatment

Distillation is a physical separation process that does not alter the molecular structure of hydrocarbons

feedstocks for secondary conversion units. The unvaporised portion, or residual fuel, is siphoned off for further processing in vacuum or thermal units.

2. Conversion processes

Cracking conversion process

Cracking is a volumetrically expansive conversion process, which can employ heat, pressure, chemical catalysts and hydrogen individually, or in unison, and is used to promote chemical change and reduce the molecular structure of the hydrocarbon molecules. The cracking process essentially breaks up heavier high boiling-range feedstocks like heavy gas oils and residue into lighter products such as gasoline, LPGs and light distillates. There are three main cracking processes: catalytic cracking, hydrocracking and thermal cracking (coking).

Cracking reduces the molecular structure of the hydrocarbon molecules

(a) Catalytic cracking

The **fluid catalytic cracker** (FCC) utilises heat, pressure and a metallic catalyst to convert heavy straight-run gas oils and vacuum gas oils into gasoline. Cat crackers are used extensively in the gasoline leveraged markets of North America and Western Europe. Cat crackers are also a primary source of olefins (chemical feedstocks). A major problem with cat gasoline is its high sulphur content. New sulphur regulations in Europe and the United States will require significant and potentially expensive hydrotreating of either the cat gasoline itself or some of the gas oil streams that are fed into the front end of the unit.

The fluid catalytic cracker converts heavy gas oils into gasoline, high-value gaseous streams and light distillate oils

(b) Hydrocracking

Catalytic cracking is a very hydrogen-deficient operation, which generates highly sulphuric and aromatic products. These harmful compounds require further blending and treatment for environmental compliance.

Catalytic cracking is a very hydrogen-deficient operation, which generates highly sulphuric and aromatic products

The **hydrocracker** addresses this problem through the introduction of hydrogen to the cracking process. In addition to producing cleaner final products, hydrocrackers offer much greater processing flexibility than do standard FCCs. A hydrocracker can be optimised for gasoline production (yielding 110% of feed), jet fuel production (70%) or diesel production (85%). This flexibility of course comes at a price: the high expense of a standalone hydrocracker and its associated hydrogen-generating infrastructure, generally make it the costliest facility in a refinery (hundreds of millions of dollars).

(c) Thermal cracking: coking

The **coking** process reduces the yield of low-value heavy products. Coking is the most severe form of thermal cracking, and can eliminate 100% of the residual oil feed. The process employs great heat at moderate pressure to convert fuel oil into naphtha, gas oils and coke. The process is designed to produce maximum yields of transportation fuels and can be used where there is little or no fuel oil demand. However, the coking process is very expensive, and can increase overall plant operating costs by up to 20% per barrel.

The coking process reduces the yield of low-value heavy products

Non-cracking conversion processes

(a) Catalytic reforming

Reformers are primarily designed to convert low-octane naphthas into high-octane blending components. Reforming actually rearranges molecules rather than cracking them, so there is no yield gain in this procedure. The process yields hydrogen and reformate, a highly aromatic gasoline feedstock. The catalytic reformer is a minimum requirement for simple refineries wishing to produce gasoline with sufficient octane content. Such refineries are referred to as **hydroskimmers** due to the excess hydrogen produced by the catalytic reforming process.

Reformers are primarily designed to convert low-octane naphthas into high-octane blending components

(b) Alkylation/isomerisation

Unlike cracking, these two conversion processes actually increase the size of the molecules processed. **Alkalisiation** and **isomerisation** often work in tandem, converting naturally occurring and cracked gaseous by-products into high-quality gasoline blending components. Alkylate is, in fact, almost the perfect blending component due to its high octane rating (89-97) and low vapour pressure (4.6). Alkylation units utilise either sulphuric acid or hydrofluoric acid catalysts and are therefore very dangerous to operate.

Alkalisiation and isomerisation convert naturally occurring and cracked gaseous by-products into high-quality gasoline blending components

3. Treatment/blending

Treatment is the final stage of finished product development. The primary treatment vehicle is **blending**. Blending processes are generally designed to bring different constituent streams together in an attempt to achieve minimum product quality standards. Unlike conversion, the blending process does not alter a specific product's chemical composition, but rather enhances it through addition or dilution. One of the best examples of gasoline blending is the introduction of ethers like MTBE. The addition of MTBE raises the octane level of gasoline (additive) while simultaneously promoting more complete combustion of free-form contaminants (dilutive).

Blending processes are generally designed to bring different constituent streams together in an attempt to achieve minimum product quality standards

Crude slate

Different crude oils have widely different qualities, and therefore produce very different yields when refined. The lighter the crude, the higher the proportion of light products to residue. For example, a light crude such as **Brent** will produce a higher yield of gasoline and a lower percentage of residual fuel oil than a heavy crude like **Maya**. However, since light crudes are more expensive, refinery profitability is partly determined by optimal combination of process and crude selection. The crude feedstock into a particular refinery is known as the **crude slate**. Successful downstream petroleum operations are based upon a company's ability to add the greatest value to cheapest crude oil available under the most economic operating conditions.

Different crude oils have widely different qualities

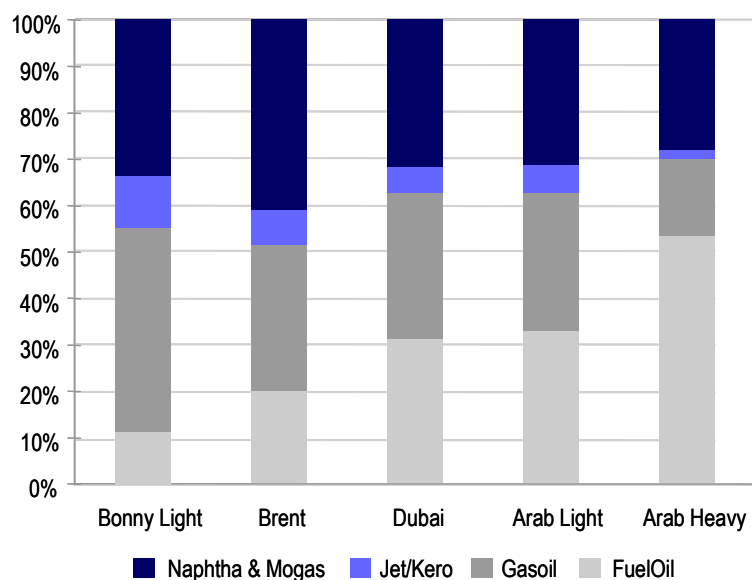
Crude oil prices vary in direct proportion to the quality and quantity of their constituent products. Proxies for gauging these qualitative differentials are weight (or viscosity) and sulphur content.

Product slate

The **product slate** describes the types and volumes of products produced and is dependent on the characteristics of the refinery and the type of crude used as feedstock. The diagram below shows the variation in product yields with crude type for a typical North West European (NWE) catalytic cracking refinery.

Light crudes produce a higher yield of light products than heavier crudes

Chart 39: Variation in product yields with crude (for a NWE cat cracking refinery)



Source: UBS

Finished petroleum products

As discussed in the previous section, different types of refineries and different crudes will produce different product yields. We describe below the major product categories (in ascending order of molecular weight).

Petrochemical feedstocks, LPG. The output of finished products at the lightest end of the distillation range can vary greatly, depending on the sophistication of the refinery. The gaseous products at the upper end of the distillation curve can be reprocessed into high-quality gasoline components, sold as heating or transportation fuels, upgraded into higher value petrochemical products, or simply burned as a refinery fuel source. **Propane** and **butane** are both termed liquefied petroleum gas (LPG), and can also be produced from reforming and cracking. Once distilled, LPGs are liquefied and either sold in bottles, used for gasoline blending or as ethylene steam cracker feedstock to manufacture base chemicals. Heavier products such as **naphtha** (essentially untreated gasoline) are primary feedstocks for the European petrochemical industry.

Petrochemical feedstocks, LPG

Gasoline (petrol, mogas). Gasoline, the primary transportation fuel of the OECD, is favoured in developed nations for its superior combustion and low pollution characteristics. Finished gasoline is composed of straight run gasoline (from the distillation column), treated **naphtha** (reformer), treated **cracked gas oil** (cat cracker, hydrocracker), **alkylate**, **isomerate** and **blending components** (primarily ethers). These gasoline pool constituents are blended together to achieve the desired balance of engine performance and emission reductions. Increasingly stringent European and North American gasoline specifications require a growing degree of sophistication among gasoline producing refiners.

Gasoline (petrol, mogas)

Kerosene (jet fuel/space heating, cooking oil). Kerosene, the original refined product, falls within the lightest distillate class, with a boiling range of approximately 160 to 270 degrees centigrade. Kerosene was originally used to replace whale oil as an illuminant, and over time, its use was adapted for cooking and space heating needs. Today, kerosene is primarily consumed in jet and turbine engines. Kerosene's volatility and pour point fall between that of gasoline and diesel fuel. It is important for jet fuel to maintain very consistent ignition and physical flow characteristics over a broad range of atmospheric conditions. A high flash-point prevents premature explosions in overheated aeroplane tanks (and bullet-compromised tanks in military aircraft) while a low pour point ensures that the jet fuel flows to the engines under subzero temperatures at high altitude. The purity and low smoke requirements of jet fuel necessitates extensive hydrotreating. Primary sources of finished jet fuel are **hydro-treated straight-run kerosene** and **hydrocracked gas oil**.

Kerosene

Distillate fuel oil (gas oil/diesel/heating oil). These medium distillates have a boiling range of 190 to 340 degrees centigrade. Different grades are used for transportation, residential heating, light industrial and commercial uses, and as a feedstock for secondary processing units and petrochemical plants. Mid-range diesel fuels are primarily differentiated by ignition quality (**cetane number**) and sulphur content. On-road diesel fuel has a higher cetane number (low self-ignition temperature) and a lower sulphur content than heating oil. Higher cetane grades offer better cold-starting characteristics and reduced smoke emissions.

Distillate fuel oil

Sulphur reduction is the primary focus of environmental regulation for middle distillates. Sulphur reduction is primarily achieved through hydrotreating.

Residual fuel oil (fuel oil, bunker fuel). Residual oil, often referred to simply as resid, is the heaviest, most contaminated constituent of crude oil. In fact, it is the only cut that isn't vaporised in the distillation column. Resid is the heavy 'residual' liquid drained off from the bottom of the distillation tower at the tail end of the distillation process. Residual fuel reigned supreme during the early periods of centralised, pollution-insensitive industrial development. Heavy industry, utilities and shipping concerns prized resid for its high caloric content, low volatility and ease of transportation and storage. Unfortunately, the majority of crude oil's sulphur and heavy metals reside within the residual boiling range. These contaminants, along with resid's inherently low hydrogen to carbon ratio, conspire to make residual fuel the most polluting of all petroleum products, rendering its combustion undesirable in most developed economies. Over the last two decades US residual fuel oil consumption has diminished by over 70%. In the world's more sophisticated energy markets, most residual fuel is reprocessed in cokers and or converted into asphalt. Power plants and large industrial customers still burn significant volumes of treated or naturally occurring low-sulphur resid and shipping demand accounts for the balance of high-sulphur residual consumption (bunkers).

Residual fuel oil

Petroleum coke. This black solid residue is obtained mainly by thermally cracking residue feedstock, tar and pitches. It mostly consists of carbon and is used as a feedstock in coke ovens for the steel industry; for heating purposes; for electrode manufacture and for the production of chemicals. In some markets, like the US West Coast, there is no local demand for coke and regional refiners are occasionally forced to pay foreign buyers to remove the product off-shore.

Petroleum coke

Asphalt/bitumen and road oil. Produced from residual oil, these products are used for road construction and roofing material. Asphalt paving is prolific in North America and the product can be quite profitable to produce. There are many small, unsophisticated refineries in the US that are solely dedicated to asphalt production.

Asphalt/bitumen and road oil

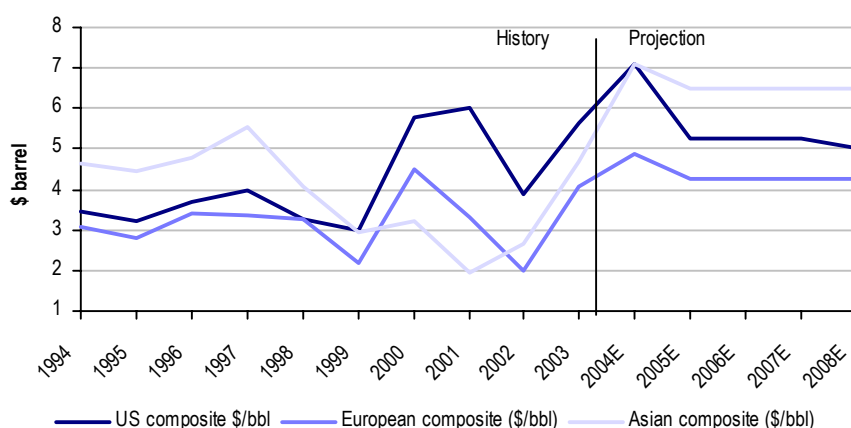
Refining margins

The primary measure of refining profitability is the **gross refining margin**. The gross margin represents the difference between the cost of feedstocks, both primary and intermediate, plus other costs such as labour, maintenance and working capital, and the revenues received for the products sold at bulk or spot.

The refining margin excludes non-cash costs (principally depreciation), hence positive refining margins may still mean a refinery is in P&L loss. Most refining margins are expressed on a per barrel basis. Each individual refinery has a unique gross margin. At any given time, margin variations among refineries can be caused by differences in product market dynamics (location), the respective crude oils processed and a facility's individual configuration. Of these three factors, geography exerts the greatest overall influence on gross margin variation. Refineries in a given location generally receive the same market prices for their products, have access to similar crude oils and therefore must adapt their respective configurations to the same set of local constraints.

Accordingly, benchmark gross reference refining margins are usually quoted on a regional basis. The three primary refining centres in the world are the **US Gulf Coast, Northwestern Europe** and **Singapore**. Margins in these areas can differ significantly, depending on the product supply/demand balance in the area as well as the availability and price of the region's price-setting marginal crude oil.

Chart 40: Refinery margins



Source: UBS

Other proxies for gross margins include simplified cash or futures **crack spreads**. Crack spreads are simplified ratios of product to crude and are often used for speculation and hedging activities. One of the most well-known crack spreads is the **NYMEX 3:2:1**. This spread is calculated by subtracting the near month NYMEX West Texas Intermediate (delivered in Oklahoma) contract price from a corresponding NYMEX product basket (67% gasoline and 33% diesel, delivered in the New York Harbor) to determine a per barrel product spread. Although the pricing information is readily available and the convention is well known, the 3:2:1 spread is purely notional, and not really representative of any individual refinery or refining region.

The primary measure of refining profitability is the gross refining margin

Refining margins are expressed on a per barrel basis

Benchmark refining margins are usually quoted on a regional basis

Crack spreads are simplified ratios of product to crude

Simple and complex margins

Refining margins differ according to the extent to which the oil has been processed, or '**upgraded**'. The more complex the refinery, the more value-added the products derived as a result.

Refining margins differ according to the extent to which the oil has been processed, or 'upgraded'

Conversion margins and the light-heavy spread

The **upgrading contribution**, or **conversion margin**, represents the difference between the cash margin from a simple refinery and one from a refinery with more sophisticated conversion capabilities. When oil prices are rising, upgrading contributions also tend to rise, since refining profitability is principally determined by the differential between the prices of light products (gas oil and gasoline) and heavy products (residual fuel oil).

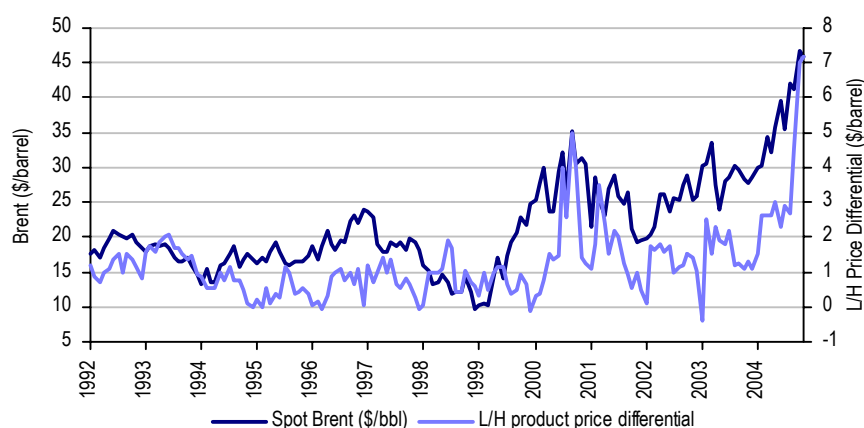
The upgrading contribution represents the difference between the cash margin from a simple refinery and a refinery with more sophisticated conversion capabilities

The prices of light products such as gasoline and diesel are not subject to short-term substitution from alternative fuels and tend to respond directly to changes in crude prices. Residual fuel oil is more subject to competition from natural gas, and to a lesser extent, coal. This is especially true in the main end-user markets. Hence, as crude oil prices rise, light products' prices and correspondingly crude oils with higher concentrations of those light products (light sweet crudes) tend to rise more in absolute terms. This widens the price spread between light and heavy crude oils and light and heavy products, which in turn benefits conversion margins.

Other factors influencing the breadth of the light/heavy spread include:

- the relative supply of high-quality and low-quality crude oils
- the relative demand for heavy and light products (gasoline versus residual fuel)
- the absolute level of conversion capacity (the capacity to process heavy oil)

Chart 41: European light/heavy product price differential, 1992 – 2004



Source: Thomson Financial Datastream

Benchmarking the refiners

The Solomon group Complexity Index

Solomon Associates, an industry body, made the first comparative performance analysis of Fuel Products refineries in 1980. The US study was expanded into Europe in 1982 and Canada and Asia/Pacific in 1983. The study aimed to examine all issues that affected commercial success – raw material selection, product yield patterns, plant utilisation levels, principal operating parameters and each major element of operating cost.

Solomon Associates, an industry body, made the first comparative performance analysis of Fuel Products refineries in 1980

Methodology

Its fundamental methodology for calculating comparative performance measurements is based on three major categories:

- (1) **Processing indicators** – This category includes measures of individual process unit availabilities and overall refinery availability, process unit utilisation and overall refinery utilisation, and the relative measures of the demonstrated capability to produce and recover saleable products.
- (2) **Resource utilisation indicators** – This category measures each refinery's cost of purchased utilities, purchased fuels, and refinery-produced fuels.
- (3) **Economic indicators** – This category calculates economic indicators that incorporate pricing issues, operating expenses, capital expenditures, replacement values, and return on investment.

Each refinery process is then ranked in a benchmarking study to examine its competitive position among these process categories.

Although widely used in the industry, the Solomon study is confidential and only available to those refineries that participate in the annual study.

The Nelson Complexity Index

In 1973, Dr WL Nelson published his attempts to relate refinery performance levels with different capacities and processing techniques. He developed a process complexity factor that related exclusively to unit investment levels. By assigning a complexity level of 1.0 to the basic crude distillation process, he was able to assign higher or lower complexity levels to other refining processes, e.g. coking plants, based on their capital investment costs relative to the crude distillation unit capital costs. His approach implied that manpower levels, maintenance costs, energy consumption and essentially all elements of refinery performance could be related to capital investment levels.

In 1973, Dr WL Nelson published his attempts to relate refinery performance levels with different capacities and processing techniques

One identified weakness of the Nelson complexity factor is that it ignores the costs associated with non-process units, e.g. receiving and shipping. Secondly, Nelson factors vary with time due to advances in technology, which can undermine their use.

Marketing

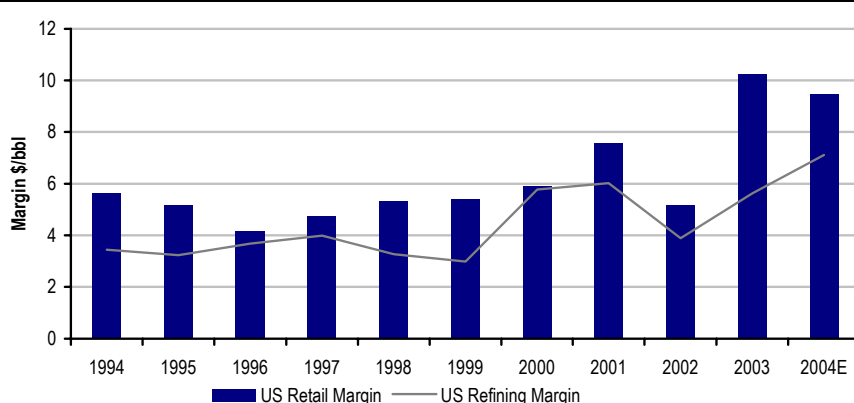
Marketing refers simply to the distribution and sale of refined product beyond the refinery gate. This can be in the form of bulk shipments from a refiner to a wholesaler, down to the selling of a tank of petrol on a garage forecourt.

The addition of marketing assets to the downstream portfolio generally creates a more stable, higher margin income stream than can be achieved through independent refining operations alone; however, in recent years retail margins have also displayed volatility, most notably in 2002. Despite this, retail margins remain larger than refining margins and have rebounded since 2002 as world demand has grown after the global economic slowdown.

Marketing refers simply to the selling of product from the refinery to the end customer

Marketing is the most important component of downstream profitability

Chart 42: Retail and refining margins



Source: UBS

Distribution channels

Methods of petroleum product distribution vary according to product and end use. Refined products in developed nations are primarily used in road transportation and are therefore ultimately distributed to individual consumers at the retail level. Heating oil (high-sulphur distillate) is also delivered to residential users through conventional retail channels. Conversely, kerosene, which is mostly consumed in commercial aircraft, is usually purchased directly from oil companies by individual airlines or through airline co-operatives. Similarly, residual fuels are often sold direct to shipping companies and utilities.

Spot. Often referred to as refinery gate pricing or bulk pricing, this is generally the lowest price paid for refined products. Spot sales are invariably conducted in large multi-thousand barrel transactions at a given day's market clearing price. Spot purchasers (speculators, other oil companies, utilities, large industrial users, etc.) are usually responsible for product transportation beyond the refinery gate.

Wholesale. The majority of refined products sold in the United States pass through some form of wholesale distribution network. The wholesale channel is divided among refiners and independent operators. Independent wholesalers can vary in size from a single tank truck operation to extensive terminal/storage

Methods of petroleum product distribution vary according to product and end use

networks. Independents are prolific in non-core refining areas where it is inefficient for a major oil company to maintain a direct presence. Wholesale margins and prices vary directly with refined product spot prices. The wholesale to spot price spread comprises a transportation differential and small return on transportation assets.

Retail. In most OECD countries, ownership of retail distribution is still fairly fragmented. However, industry consolidation has elevated the influence of major oil company brands substantially during the last decade. Retail fuel is transported either directly with oil-company owned or leased trucks (dealer tank wagons), or through independent wholesalers (jobbers).

Branded oil companies distribute fuel directly to their wholly owned and operated company sites and to sites owned or leased by independent dealers. However, the majority of US gasoline is channelled to retail chains through independent jobbers.

Marketing margins

As with refining, marketing profitability is tracked on a margin per barrel (or per tonne) basis. Also like refining, there are no standard industry margins against which to benchmark marketing performance. Instead at UBS we use indicative margins to track trends on a region by region basis.

As with refining, marketing profitability is tracked on a margin per barrel (or per tonne) basis

Similar to refining margins, retail margins display a great deal of seasonal and geographic variance. For example, in the US's weakest refining regions, the Northeast and the Gulf Coast, retail margins have historically been the highest. Conversely, some of the higher refining margin districts west of the Rockies have diminished retail spreads due partially to the relative tightness of regional gasoline supply.

Retail margins display seasonal and geographic variance

Seasonal refining and marketing divergence is also fairly consistent. During the build up to the driving season, bulk and wholesale fuel prices are elevated and marketing margins are squeezed, while slack demand periods in the fall and winter tend to yield the widest retail margins.

Spot and wholesale product prices tend to react almost instantaneously to crude price fluctuations whereas retail prices typically take up to eight weeks to fully absorb price spikes. During a typical driving season, wholesale prices rise gradually from May through the middle of August, leaving retailers behind the pricing curve. On the positive side, a deceleration of summer pricing often fails to materialise at the pump until well into the fall. These observations lead to perhaps one of the best-known truisms in the downstream industry: quickly rising crude oil prices consistently erode refining margins and almost eliminate retail margins in the short term, while falling crude prices sometimes benefit refining margins but invariably expand retail spreads.

Petrochemicals

Petrochemicals are chemicals made from crude oil and natural gas from which end products such as textiles, plastics and pharmaceuticals are made. Today, chemical operations account for approximately 5% of global integrated oil company earnings and account for 39% of the world's chemical market, with the industry producing almost 900 million tonnes of organic chemicals each year. This makes 'oil' companies some of the largest chemical companies in the world.

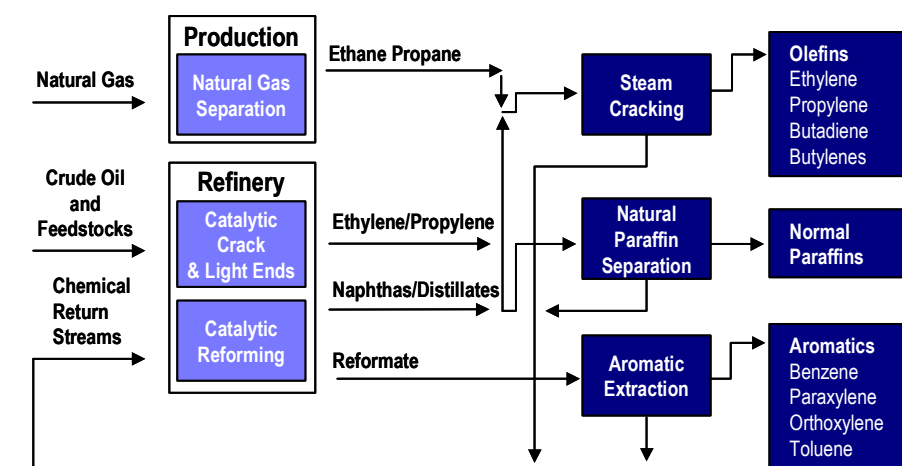
The oil industry's interaction with the chemical industry began in the 1920s when refiners sought uses for the growing number of by-products from the refining process (principally naphtha) as the economics of the industry demanded that every conceivable bit of crude was converted into a usable product.

Primary petrochemicals

Naphtha, natural gas and natural gas liquids are the principal feedstocks for the petrochemical industry, all of which are derived from crude oil and natural gas. Other feedstocks include gasoil, wax, kerosene and fuel oil. These feedstocks undergo a cracking process involving treatment with heat and pressure to produce the first generation petrochemicals, specifically:

- **olefins** (ethylene, propylene and butadiene) and
- **aromatics** (benzene, toluene and xylenes)

Chart 43: Olefins and aromatics process diagram



Source: ExxonMobil

The olefins are generally used for the production of their respective polymers, polyethylene, polypropylene or polybutylene. The major uses of aromatics are as intermediates for other chemicals such as solvents or in motor fuel to raise the octane number to help it burn more efficiently.

Petrochemicals are chemicals made from crude oil and natural gas

Naphtha, natural gas and natural gas liquids are the principal feedstocks for the petrochemical industry

Intermediates and derivatives

These primary petrochemicals can be further treated and upgraded to produce derivative chemicals and petrochemical end products. Of these derivative chemicals produced, 75% are based on ethylene, propylene and benzene which form the foundations of the industry. The other important materials are the C4 olefins (of which butadiene and isobutene are the most important), toluene, xylenes (of which paraxylene is most important) and methane.

Petrochemical derivative products can be made in a variety of ways: directly from primary petrochemicals, through intermediate products which still contain only carbon and hydrogen, or through intermediates which incorporate chlorine, nitrogen or oxygen in the finished derivative. In some cases, they are finished products; in others, more steps are needed to arrive at the desired composition.

Some typical petrochemical intermediates are:

- Vinyl acetate for paint, paper and textile coatings
- Vinyl chloride for polyvinyl chloride (PVC) resin manufacture
- Ethylene glycol for polyester textile fibres and
- Styrene, which is important in rubber and plastic manufacturing.

Polymers of petrochemicals

The process by which many of the primary and intermediate petrochemicals are converted into synthetic resins, plastics and fibres is known as polymerisation. In polymerisation, the basic units (monomers) react in the presence of a catalyst, with or without the application of heat, to form a long chain compound or polymer. Four major groups of polymers made in this way are listed in Table 3.

Table 3: Major commodity petrochemical chains

Polymer	Monomer
Polyethylene	Ethylene
Polyvinyl chloride	Vinyl chloride monomer
Polystyrene	Styrene
Polypropylene	Propylene

Source: UBS

The base chemicals

Ethylene

Ethylene is the lightest and most used hydrocarbon in the world. By itself ethylene has almost no end-use, but it is a basic chemical raw material for a variety of industrial products, either alone (polyethylene) or after reaction with other chemicals (vinyls, polyester, etc). Of the world's ethylene demand, 59% is consumed in polyethylene production. Other major derivatives are ethylene oxide/glycol (13%), ethylene dichloride (13%) and ethylbenzene/styrene (6%).

75% of petrochemicals are based on ethylene, propylene and benzene which form the foundations of the industry

Polymerisation is the process of converting primary and intermediate petrochemicals into synthetic resins, plastics and fibres

Ethylene is the lightest and most used hydrocarbon in the world.

Table 4: Major ethylene producers

Producer	Plant location	Capacity (tonnes/year)
Dow Chemical	US	7,295,000
Exxon Chemical	UK	6,365,000
Equistar Chemical	US	5,285,000
Shell & DEA Oil	Germany	4,530,000
BP Chemicals	US	3,850,000

Source: CNI

Ethylene is produced commercially by steam cracking a wide range of hydrocarbon feedstocks. In Asia and Europe, more than 90% of ethylene is obtained from cracking naphtha, gasoil and condensates with the co-production of propylene, C4 olefins and aromatics (pyrolysis gasoline). Alternatively, in the US, Canada and the Middle East, ethylene is primarily obtained by cracking of ethane and propane. This has the advantage that it only produces ethylene and propylene, making the plants cheaper to construct and less complicated to operate. The disadvantage is the lack of other petrochemical by-product revenues.

Propylene

Propylene is an important chemical used in the manufacture of plastics. It is used to manufacture many common household items such as food storage containers, diapers and children's toys. Propylene consumption is dominated by polypropylene (PP), which accounts for 60% of demand and is one of the fastest growing derivatives. Other important derivatives are propylene oxide (7%), acrylonitrile (9%), cumene (6%) and oxo-alcohols (9%).

Propylene is an important chemical used in the manufacture of plastics

Table 5: Major propylene producers

Producer	Plant location	Capacity (tonnes/year)
Shell & DEA Oil	Germany	3,060,000
Exxon Chemical	UK	2,870,000
Equistar Chemical	US	2,570,000
BP Chemicals	US	2,375,000
Dow Chemical	US	2,335,000

Source: CNI

The primary source of propylene is from cracking naphtha and other liquids, such as gas oil and condensates to produce ethylene. By altering the cracking severity and the feedstock slate, the propylene:ethylene ratio can vary from 0.4:1 to 0.75:1. Smaller amounts of propylene can be obtained from cracking propane and butane.

Toluene

Toluene is used in large quantities as an octane booster in gasoline, but most of that portion is never removed from refinery streams. Its petrochemical uses are as a feedstock for xylenes and benzene; in phenol production; in solvent use for paints, lacquers, gums and resins. It is also a chemical intermediate. Other

Toluene is used in large quantities as an octane booster in gasoline

applications include the manufacture of explosives and dyes, diluent and adhesive solvents in plastic toys and detergent manufacture.

Table 6: Major toluene producers

Producer	Plant location	Capacity (tonne/year)
ExxonMobil Chemical	Singapore	1,290,000
BP Chemicals	US	900,000
LG Group	South Korea	660,000
Shell & DEA Oil	Germany	525,000
Sunoco Chemicals	Canada	472,000

Source: CNI

The original source of toluene from coke-oven gas has been replaced by the catalytic reforming of naphthas and from pyrolysis gasoline co-produced in the steam cracking of liquid feeds. A very small amount is still produced from light oil formed by the carbonisation of coal while small quantities are recovered as a by-product in styrene manufacture.

Benzene

Benzene is used primarily as a raw material in the synthesis of styrene (polystyrene plastics and synthetic rubber), phenol (phenolic resins), cyclohexane (nylon), aniline, maleic anhydride (polyester resins), alkylbenzenes (detergents) and chlorobenzenes. Over half of benzene production feeds ethylbenzene/styrene demand. Other uses include adhesives, toys, sporting goods, appliances, automobiles, tyres and textiles.

Benzene is used primarily as a raw material in the synthesis of styrene

Table 7: Major benzene producers

Producer	Plant location	Capacity (tonne/year)
Shell & DEA Oil	Germany	2,215,000
ExxonMobil Chemical	US	2,200,000
Dow Chemical	US	1,915,000
BP Chemicals	US	1,804,950
Nippon Petrochemicals	Japan	1,105,000

Source: CNI

In Europe, benzene is obtained primarily from pyrolysis gasoline co-produced in the steam cracking of naphtha, gasoil or condensates to make olefins. The amount of aromatics produced can be increased by employing heavier feedstock.

In the US, catalytic reforming is the main source of benzene. Naphtha is mixed with hydrogen and fed into a reactor containing a catalyst and operating at 425-530°C and 7-35 bar. An aromatic-rich fraction is separated from the reformat.

Xylene

Mixed xylenes are produced by high-severity catalytic reforming of naphtha. Xylenes are also obtained from the pyrolysis gasoline stream in a naphtha steam cracker and by toluene disproportionation.

Intermediates

Ethylene glycol

Ethylene glycol's principal applications are as an intermediate in the production of polyesters and as automotive antifreeze. Around 55% of world production is used in polyester fibres, 16% in PET resin, 15% in antifreeze, 6% in other applications such as de-icing fluid and surface coatings and 3% in other polyesters. There are three grades of ethylene glycol: fibre grade, industrial grade and antifreeze grade.

Specific applications include its use as a heat-transfer fluid in aircraft and runway de-icing mixtures, to provide freeze-thaw stabilisation to latex coatings, to improve flexibility and drying time of oil-based paints containing alkyd resins, as a dehydrating agent for natural gas, in motor oil additives, and as an additive in the formulation of inks, pesticides, wood stains, adhesives and other products.

Phenol

The primary chemical intermediates and derivatives of phenol include phenolic resins, bisphenol-A (BPA), caprolactam, adipic acid and plasticisers. Phenolic resins are used for adhesives, binders for insulation and for moulding compounds. As the use of polycarbonates increases, bisphenol-A emerges as the main outlet for much of the phenol production. Strong growth is also projected for the use of phenol in polyphenylene oxide engineering plastics, via ortho-xenol, although from a relatively small base. Phenol is also used as a slimicide, which is a chemical toxic to bacteria and fungi; as a disinfectant; and as an anaesthetic in medicinal preparations including ointments, ear and nose drops, cold sore lotions, throat lozenges and antiseptic lotions.

Acrylic acid

Acrylic acid has traditionally been used to produce solvent-based acrylic resins. However, environmental concerns over solvent use led to the development of water-based acrylics. Applications for water-based acrylics are primarily in decorative, masonry and industrial coatings. Since the mid-1980s, two new applications – superabsorbent polymers (SAPs) and detergent polymers – have emerged, and now account for nearly 40% of world acrylic acid consumption.

SAPs are cross-linked polyacrylates with the ability to absorb and retain more than 100 times their own weight in liquid. They have experienced very strong growth, primarily in baby diapers.

Detergent polymers can be used with both zeolites and phosphates in washing powder formulations. Use of detergent polymers grew strongly in western Europe from the mid-1980s as phosphate-based detergents were phased out and, more recently, their use in the US has increased.

Ethylene glycol's principal applications are as an intermediate in the production of polyesters and as automotive antifreeze

Phenolic resins are used for adhesives, binders for insulation and for moulding compounds

Acrylic acid has traditionally been used to produce solvent-based acrylic resins

Acetic acid

Principal uses are as a chemical intermediate and solvent in chemical reactions. Its main use is in vinyl acetate monomer, used to make protective coatings, adhesives and plastics, and accounts for about 44% of the consumption. PTA production accounts for around 18%, solvent esters 14% and acetic anhydride, used primarily in cigarette filters, about 13%.

Principal uses are as a chemical intermediate and solvent in chemical reactions

Styrene

Styrene is mainly used in the manufacture of homopolymers and copolymers. Its predominant use is in polystyrene (66%), of which 50% is in the manufacture of general purpose (GP) and high impact (HI) polystyrene (PS), and 16% in expanded polystyrene. Other uses include styrene-butadiene rubber and latex (11%) as well as ABS/SAN resins (14%)

Styrene is mainly used in the manufacture of homopolymers and copolymers

There is a wide range of end uses for styrene's derivatives including packaging, construction materials, automotive parts including tyres, household goods, electrical appliances and electronic cases, and drinking cups and other food use items.

Xylenes

Xylene is used as a solvent in the printing, rubber and leather industries. It is also used as a cleaning agent, as paint thinner and in paints and varnishes. Together with toluene, it is also a key ingredient in unleaded gasoline. There are three commercial isomers of xylene, metaxylene (MX), paraxylene (PX) and orthoxylene (OX).

Xylene is used as a solvent in the printing, rubber and leather industries

Metaxylene (MX)

MX is used primarily as the feedstock for the manufacture of purified isophthalic acid (PIA), an intermediate for higher quality unsaturated polyesters and as a modifier for PET (polyethylene terephthalate) resins.

Paraxylene (PX)

Virtually all PX produced is consumed in the manufacture of purified terephthalic acid (PTA) which, in turn, is used to produce polyester fibre, resin and film, and dimethyl terephthalate (DMT), with a small amount used as a solvent and in the manufacture of di-paraxylene and herbicides.

Orthoxylene (OX)

OX is the second largest of the three commercial xylene isomers. Almost all OX produced is used in the manufacture of phthalic anhydride, which is converted to plasticisers, alkyd and polyester resins. Small quantities are used in solvent applications and to make bactericides, soybean herbicides and lube oil additives.

End-products (the plastics)

Polyethylene

The manufacture of most resins or plastics begins with the polymerisation or linking of the basic compound (monomer), usually a gas or liquid, into high molecular weight non-crystalline solids. The manufacture of the basic monomer is not considered part of the plastics industry and is usually carried out at a chemical or petroleum plant. The manufacture of most plastics involves an enclosed reaction or polymerisation step, a drying step, and a final treating and forming step. These plastics are polymerised or otherwise combined in completely enclosed stainless steel or glass-lined vessels. Treatment of the resin after polymerisation varies with the proposed use. Resins for mouldings are dried and crushed or ground into moulding powder. Resins, such as the alkyd to be used for protective coatings, are usually transferred to an agitated thinning tank, where they are thinned with some type of solvent and then stored in large steel tanks equipped with water-cooled condensers to prevent loss of solvent to the atmosphere. Other resins are stored in latex form as they come from the kettle.

HDPE

High Density Polyethylene (HDPE): HDPE refers to a plastic used to make bottles for milk, juice, water and laundry products. Unpigmented HDPE bottles are translucent and have good barrier properties and stiffness. They are well suited for packaging products with short shelf life such as milk, margarine tubs and yoghurt containers. Because HDPE has good chemical resistance, it is used for packaging many household products as well as industrial chemicals such as detergents and bleach. Pigmented HDPE bottles generally have better stress crack and chemical resistance than bottles made from unpigmented HDPE.

HDPE refers to a plastic used to make bottles for milk, juice, water and laundry products

LDPE

Low Density Polyethylene (LDPE): A plastic employed predominately in film applications due to its toughness, flexibility and relative transparency, making it popular in applications where heat sealing is necessary. LDPE is also used to manufacture some flexible lids and bottles and in wire and cable applications because of its properties and processing characteristics. LDPE is also used in sheathing for electrical and communication cables, the extrusion coating of paper and board for the packaging of liquids and in moisture barrier applications.

LDPE is a plastic employed predominately in film applications due to its toughness, flexibility and relative transparency

LLDPE

LLDPE is a thermoplastic, which, in many applications, replaces its predecessor – low-density polyethylene (LDPE) – or is used in blends with LDPE. In particular, LLDPE's short chain branching gives it higher tensile strength, puncture and anti-tear properties, making it particularly suitable for film applications. Other outlets include injection moulding products and wire and cable. Metallocene-based LLDPE resins are penetrating the film and packaging markets due their enhanced physical properties, while catalyst developments should improve their processability.

LLDPE's short chain branching gives it higher tensile strength, puncture and anti-tear properties, making it particularly suitable for film applications

Polyvinyl chloride (PVC)

There are two types of PVC homopolymers: rigid resins which are inflexible and hard; and flexible resins which contain a large proportion of plasticiser to make them soft and stretchable. Polyvinyl Chloride or PVC: in addition to its stable physical properties, PVC has good chemical resistance, good weatherability, flow characteristics and stable electrical properties. The diverse slate of vinyl products can be broadly divided into rigid and flexible materials. Bottles and packaging sheets are the major rigid markets, but vinyl is also widely used in the construction market for applications such as pipes and fittings, siding, carpet backing and windows. Flexible vinyl is used in wire and cable insulation, film and sheet, floor coverings, synthetic leather products, coatings, blood bags, medical tubing and many other applications.

PVC has good chemical resistance, good weatherability, flow characteristics and stable electrical properties

Polypropylene (PP)

Polypropylene has good chemical resistance, is strong and is the lowest density plastic used in packaging. It has a high melting point, making it ideal for hot-fill liquids. PP is found in packaging products, flexible and rigid packaging to fibres and large moulded parts for automotive and consumer products.

Polypropylene has good chemical resistance, is strong and is the lowest density plastic used in packaging

Polystyrene (PS)

Polystyrene is a very versatile plastic that can be rigid or foamed. General-purpose polystyrene is clear, hard and brittle, and has a relatively low melting point. Typical applications include protective packaging, containers, lids, cups, bottles and trays. Extruded polystyrene foam sheets are formed into egg carton containers, meat and poultry trays, and fast-food containers requiring hot or cold insulation. Solid polystyrene sheets are formed into drinking cups and lids, and disposable food packaging. Durable goods, including house ware and furniture, are also made of polystyrene.

Typical polystyrene applications include protective packaging, containers, lids, cups, bottles and trays

Polyethylene terephthalate (PET or PETE)

Polyethylene terephthalate (PET or PETE): PET is transparent, tough and has good gas and moisture barrier properties. This plastic is commonly used in soft drink bottles and many other injection-moulded consumer product containers. Other applications include strapping, moulding compounds and both food and non-food containers. Demand for cleaned and recycled PET flakes and pellets is high in the areas of spinning fibre for carpet yarns and producing fibrefill and geotextiles. PET is also known as polyester.

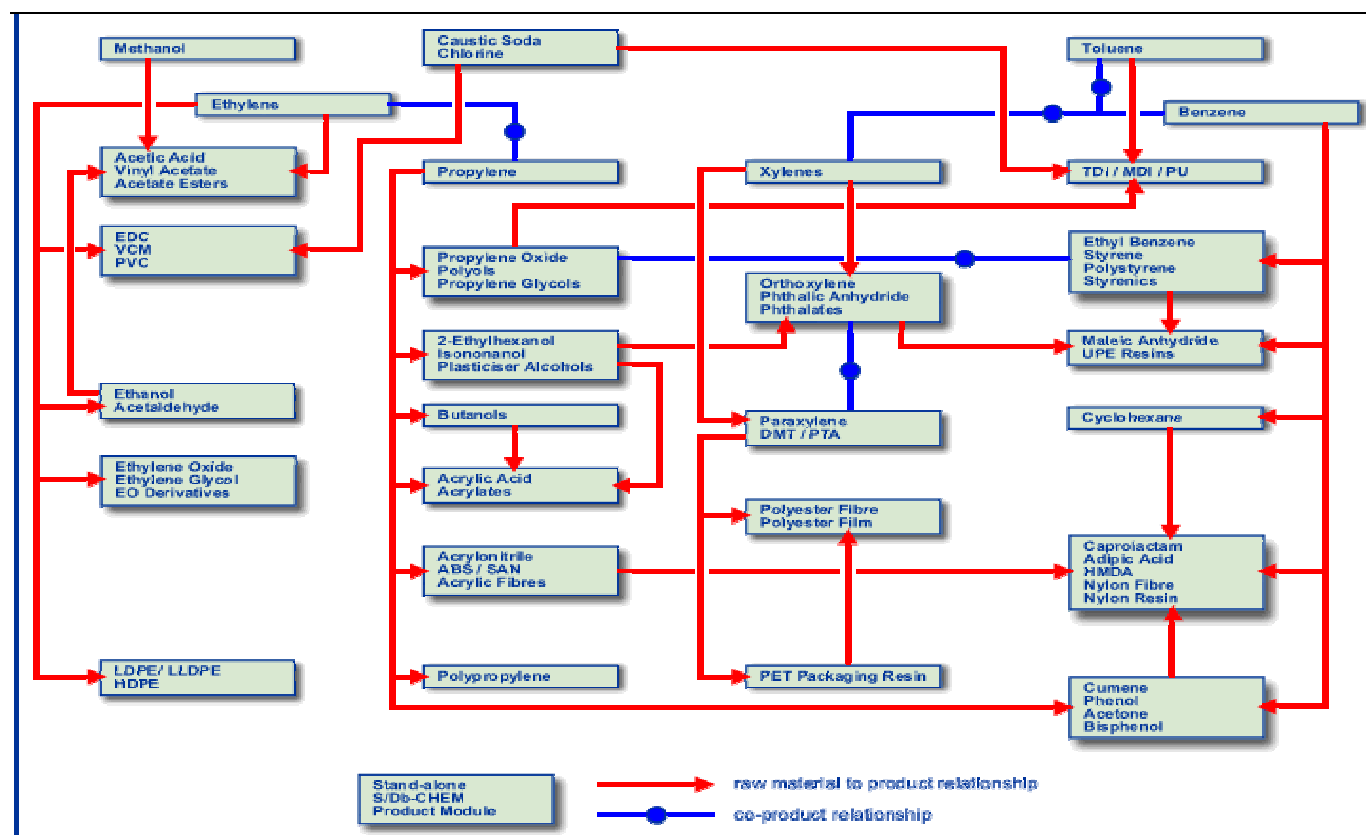
PET is commonly used in soft drink bottles and many other injection-moulded consumer product containers

Purified terephthalic acid (PTA)

Purified terephthalic acid (PTA) is primarily used in polyester production, with polyester fibre consuming a large proportion of global output. However, polyethylene terephthalate (PET) resin production for packaging and film applications is growing rapidly due to its success in penetrating the soft drink and water bottle market. A smaller proportion of PTA is utilised in the production of polyester film, which had, until recently, been the material of choice for the audio recording industry. The remaining PTA is used to manufacture polybutylene terephthalate, cyclohexanedimethanol, terephthaloyl chloride, copolyester-ether elastomers, plasticisers and liquid crystal polymers.

Relationships among major petrochemicals

Chart 44: Relationships among major petrochemicals



Source: Technon Consulting

Chemical margins

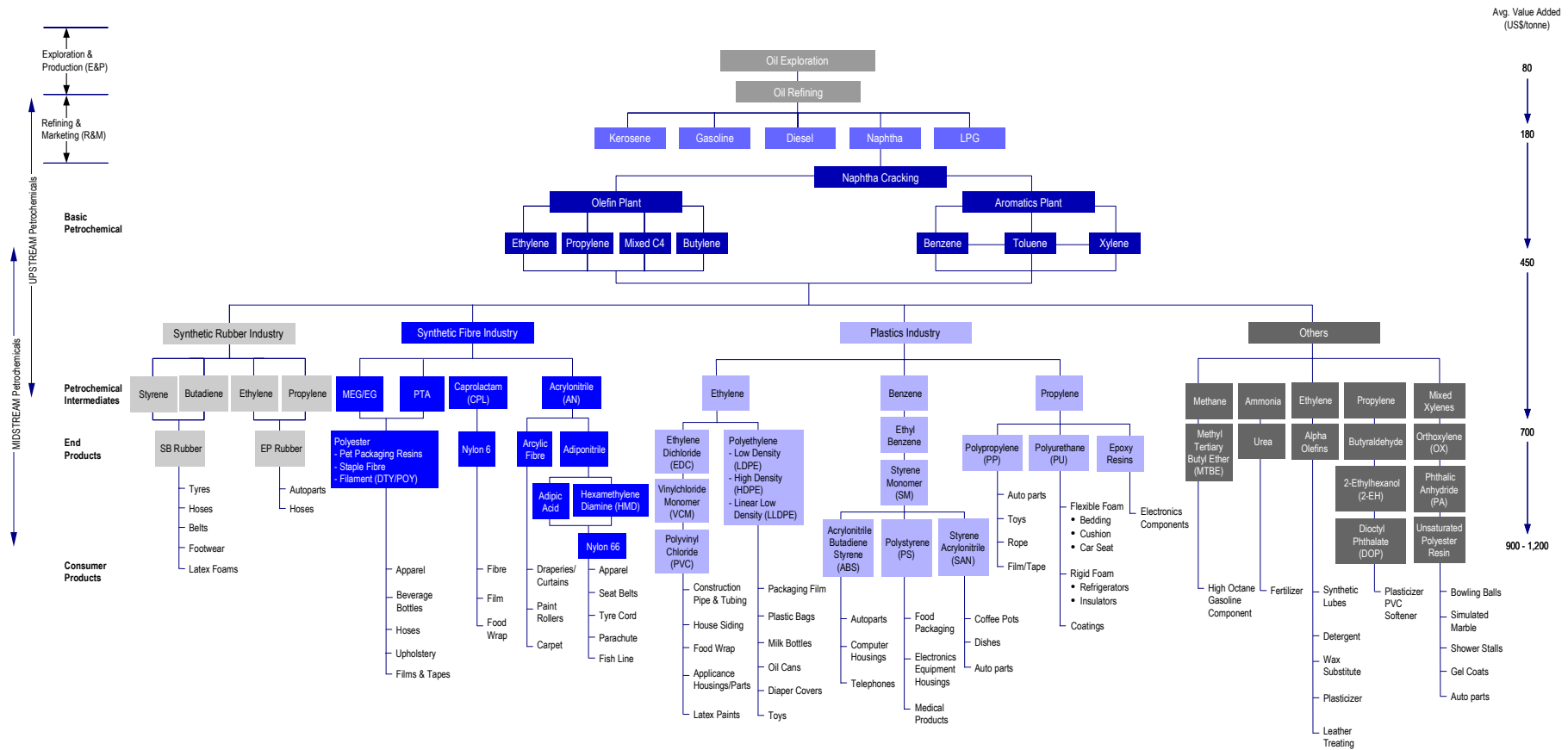
The ethylene cash margin represents the margin achievable per tonne of ethylene produced from an industry 'leading' steam cracker, based on naphtha feedstock after the deduction of all cash costs (feedstock, utilities and other operating costs including an element of allocated overheads).

In a typical steam cracker, more than three tonnes of naphtha are utilised to produce one tonne of ethylene. The other co-products in the manufacture of ethylene (propylene, butadiene, benzene and gasoline components) are represented in the calculation of the ethylene margins as credits based on their market value. The cost elements in the calculation are adjusted periodically to reflect changing industry productivity and operating standards.

The cash margins for the major polymers are calculated in a similar manner; monomer feedstock (ethylene or propylene) and other cash production costs are deducted from the market value of the polymer output. Margins on the various polyethylene grades generally move in tandem, but those for polypropylene, derived from propylene, occasionally move separately from the other major polymers. In Europe, most polymer production is integrated with monomer production at the same site. It is therefore appropriate to look at the combined monomer and polymer margins at such sites, expressed per tonne of polymer produced, as an indicator of profitability.

The ethylene cash margin represents the margin achievable per tonne of ethylene produced from an industry 'leading' steam cracker

Industry flow chart



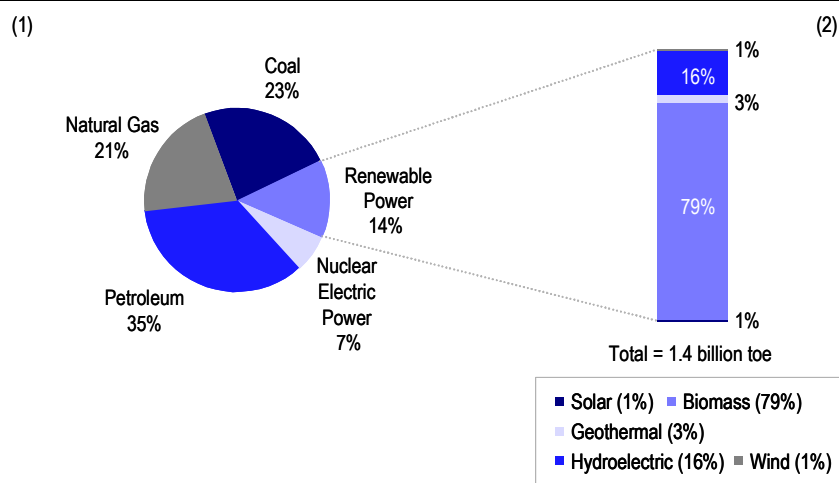
Source: UBS

Renewable fuel sources

Renewable fuel sources are increasingly being turned to as environmental concerns, depleting reserves and the desire for reduced reliance on Middle Eastern oil become ever more pressing concerns. Coupled with this, recent technological advances have made these processes more commercially viable by bringing down their often prohibitive cost structures.

The UN believes the resource potential of renewable energy sources to be many times the world's present energy demand, however in 2002 renewable energy consumption accounted for only 1.4 billion tonnes of oil equivalent or 14% of global primary energy consumption (see graph). This proportion of energy consumption is usually much larger in developing countries, where most biomass and hydroelectricity operations are found. Conversely, wind and solar energy schemes tend to be more concentrated in the developed world.

Chart 45: ⁽¹⁾ World energy consumption by fuel (including alternate power sources); and ⁽²⁾ Breakdown of renewables share of primary energy



Source: IEA

Despite renewables' attractive environmental and political attributes, the IEA offers only extremely conservative predictions of the proportion of energy that will be derived from renewable sources in developed economies over the next 20 years. Global reserves of fossil fuels remain high (despite what some commentators have suggested), governments are yet to give their full backing to renewable projects and many of these methods remain uncommercial.

These hindrances to growth, however, are all slowly subsiding. First, oil reserves, although not scarce, are becoming more expensive to exploit as they become increasingly remote. Second, the exponential rate of technological improvement is heightening the competitiveness of renewable energy; and finally, despite the continued refusal of the US to sign up to the Kyoto Protocol, renewable fuel sources are beginning to receive at least token governmental support and funding.

Renewable fuel sources are increasingly being turned to

The UN believes the resource potential of renewable energy sources to be many times the world's present energy demand

Of these three influences, political resolve is most crucial in order to balance environmental and economic trade-offs, as the current economics of renewable energy remain unfavourable compared with those of conventional technologies utilising fossil fuels.

Biomass

Including both commercial and uncommercial sources, biomass accounts for 10.9% of world energy consumption, or 1.1 billion tonnes of oil equivalent a year (uncommercial sources include subsistence-type energy sources such as wood burning fires and the like).

Biomass is an all-encompassing term used to describe any vegetation from which energy can be extracted. This energy is created through photosynthesis, which harnesses solar energy, carbon dioxide and water to produce carbohydrates which then form fuel. These carbohydrates can either be burnt to release energy or converted into liquid fuels used for transportation. The two most common of these biofuels are ethanol and biodiesel.

Ethanol is an alcohol made through a fermentation of barley, wheat or sugar cane (among other feedstocks), which can then be used as a fuel additive to reduce a combustion engine's carbon monoxide emissions. Many vehicles already in service can run on blends of ethanol and gasoline (typically this is only 10% ethanol although three million FFV's or flexible fuel vehicles have already been sold in the US which can run on an 85% ethanol mix). It has been estimated that this blending is already reducing the US' dependence on oil by 98,000 barrels per day. One day ethanol may also be used to produce hydrogen for fuel-cell vehicles.

Biodiesel is the product of mixing alcohols with vegetable oils or animal fats, which can again be used as a fuel additive to reduce emissions, or in its purest form as an alternative to diesel itself.

One of the key advantages of biomass is its carbon dioxide neutrality. Although biomass generates a similar amount of carbon dioxide as fossil fuels, the carbon dioxide released from biomass was previously extracted from the environment by the organic matter as it grew. Therefore, as long as biomass feedstocks are continually replenished, net carbon dioxide emissions will be zero.

Along with hydro-electricity, biomass dominates the current supplies of energy from renewable sources; however, being a cost effective and scalable process, biomass should see its importance grow over coming decades as it can be introduced without major changes to existing energy infrastructures.

Hydroelectricity

Hydroelectricity now accounts for about 20% of the world's electricity generation. This equates to 220 million tonnes of oil equivalent a year, which is estimated to be only a third of its total potential. Indeed the UN forecasts that global hydroelectricity production will more than double by 2050. In some countries hydroelectricity has already assumed a more prominent role, for

Biomass is an all-encompassing term used to describe any vegetation from which energy can be extracted

One of the key advantages of biomass is its carbon dioxide neutrality

example in Norway hydroelectricity is responsible for almost all electricity generation.

The advantages of hydroelectricity are its lack of emissions of greenhouse gases and its ability to handle seasonal high-peak loads. The disadvantage is the environmental disruption it causes in the flood planes of the dammed rivers.

Geothermal

Geothermal energy supplies 0.4% of the world's energy needs, or 41 million tonnes of oil equivalent in 2002.

Geothermal energy supplies 0.4% of the world's energy needs

Geothermal energy is energy derived from the natural heat of the earth, which is used to heat water, turning it into steam, which can then drive turbines. For commercial use high-temperature reservoirs (greater than 150°C) are required. These reservoirs are found in geothermal systems, which are localised areas where the earth's crust is particularly thin, enabling core heat to be accessible from the surface.

Geothermal energy has been used commercially for 70 years, although the last 30 years have witnessed a sharp increase in its uptake. In the 20 years to 1995 geothermal electricity generation experienced a 9% annual growth rate. This has now slowed to 4% per year but with no further slowdown forecast this still represents considerable growth, suggesting geothermal energy will make a significant contribution towards reducing the emissions of green house gases. Additionally, this technology is relatively cheap, with new power plants able to produce electricity for a similar cost to coal-burning plants.

Wind

Wind energy currently accounts for less than 0.1% of total world energy consumption and approximately 0.5% of world power generation. Although a low number, generation capacity has grown at an average rate of 30% per annum over the last decade, with BP estimating that this rate will continue for the foreseeable future. This suggests that the quantity of electricity wind energy produces will double every three years.

Wind generation capacity has grown at an average rate of 30% per annum over the last decade

This growth has been aided by supportive government policies and cost reductions resulting from technological improvements. Costs are forecast to continue falling by up to 45% over the next decade, enabled largely through economies of scale resulting from larger turbines which will enable wind energy to compete favourably with conventional energy sources.

Three quarters of the world's wind generation capacity is in Europe with Germany, Spain and Denmark being the major contributors, although capacity is also growing elsewhere, particularly in the US and India.

The recent trend has been to locate wind farms offshore, further enhancing the scale of these operations. In Europe studies have shown enough tappable offshore resources to meet Europe's total electricity demand.

The only concerns with wind energy are the inevitable output fluctuations, leading this to be an intermittent power supply, and local opposition to wind farm locations – although this is less of a problem with offshore sites.

Solar

Solar energy in all its guises currently accounts for 0.1% of world energy supplies. The UN estimates global solar energy potential at between 1,575 and 49,837 exajoules annually, depending on cloud cover. This energy is primarily harnessed in two ways, either to make electricity (photovoltaics) or to heat water (solar thermal). Of these two, photovoltaic electricity production is larger (with 1.33 gigawatts of installed capacity in the OECD) and faster growing (currently at rates of over 35% per year). Photovoltaic systems supply almost 1% of the world's electricity.

Like other forms of renewable energy, solar energy costs are falling dramatically, making this a more accessible technology, especially to remote parts of the developing world for which other methods of power generation are not feasible. For example, BP recently started work on a solar project to provide power to a community of over 400,000 people in the Philippines. The potential for such projects is huge, in light of the fact that a third of the world's population still live without electricity due largely to infrastructural complications.

Solar energy in all its guises currently accounts for 0.1% of world energy supplies

Fuel cells

Fuel cells are now technically if not yet widely commercially viable energy conversion devices, potentially capable of competing with more familiar conversion technologies, ranging from internal combustion engines (ICEs) to batteries.

Fuel cells offer the prospect of competing with these entrenched technologies on price, and have the added advantage of being extremely efficient and clean. While both fuel cells and batteries convert energy electrochemically, batteries store their fuel internally in toxic media and must be disposed of or recharged when the fuel is exhausted. In contrast, fuel cells are fuelled externally, like combustion engines, and likewise will run as long as the fuel is supplied. ICEs burn their fuel at high temperatures, thereby producing not only such pollutants as oxides of sulphur and nitrogen as well as particulate matter but also significant quantities of the greenhouse gas carbon dioxide. Fuel cells convert hydrogen and oxygen electrochemically, producing only heat, water and electricity.

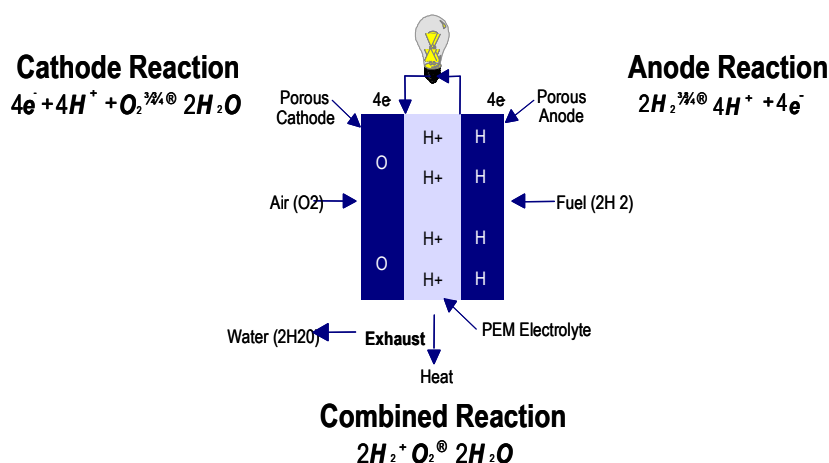
Fuel cells offer the prospect of competing with entrenched technologies on price, and have the added advantage of being extremely efficient and clean

How do fuel cells produce electricity?

There are five types of hydrogen fuel cell, each with its own unique advantages and disadvantages. While the details of precisely how the different fuel cells create electricity differ, the basic process remains largely the same.

A fuel cell essentially consists of an ion-conducting material (electrolyte), two electrodes (a cathode and an anode) and two bipolar plates. The diagram below shows the operation of a Proton Exchange Membrane Fuel Cell, (PEMFC), the variant most commonly reported in the press.

Figure 10: Proton exchange membrane fuel cell



Source: Adapted from schematic in DoE's Fuel Cell Handbook, 1998

The hydrogen gas molecules (H₂) are fed to the porous anode where they are broken up into atoms (H) and stripped of their electrons, leaving hydrogen ions (H⁺). While the electrolyte conducts positively charged hydrogen ions to the cathode, it acts as a barrier to the negatively charged electrons, which are forced

to make their way to the cathode via the external circuit, powering whatever device the system is attached to in the process. On the cathode side, oxygen molecules (O_2) are broken up into single oxygen atoms (O), which attract (two) positively charged hydrogen ions through the electrolyte and (two) negatively charged electrons from the external circuit. The final product is water or steam (H_2O) and heat. As can be seen from the anode and cathode reactions given above, for every two water molecules ‘produced’ or exhausted, the cell ‘consumes’ two hydrogen atoms and one oxygen atom. This process produces no pollution whatsoever.

What fuels the fuel cell?

As noted, fuel cells consume hydrogen, but hydrogen is not freely available and as such has to be extracted from a ‘feedstock’ using a device called a fuel reformer, which chemically extracts the hydrogen from the fuel supply and feeds this into the fuel cells.

Hydrogen can be extracted from several sources. Apart from cracking hydrogen from water, it can also be extracted from any carbonaceous fuel including petrol, diesel, natural gas, methanol and ethanol, using a reformer.

Essentially there are three issues to address:

- The technical problems associated with the storage and transportation of hydrogen.
- The astronomical capital cost of installing a hydrogen infrastructure.
- The problem of producing hydrogen for a mass market in a cost-competitive way.

In part to address these issues, and in conjunction with the development of fuel cells, fossil fuel reforming methods are being developed which will enable the employment of fuel cells ahead of the installation of a hydrogen infrastructure.

Whilst we do not doubt that the world will move towards becoming a self-sufficient ‘hydrogen economy’, this is likely to come in two stages:

The first stage of transition will begin with the introduction of cleaner, more efficient conversion technologies like fuel cells which, with the aid of catalytic fuel-reforming technology, will initially exploit carbonaceous fuels. Thus while we await the resolution of the substantial issues still dogging the deployment of the ‘hydrogen economy’, we can start the transition with a more efficient exploitation of fossil fuels. On the one hand the significantly higher fuel efficiency of fuel cells over combustion engines, combined with the fact that the hydrogen is extracted catalytically in the reformer, reduces carbon dioxide emissions by up to 50% per unit of fossil fuel used. On the other hand, the electrochemical process employed avoids the creation of local pollutants such as NO_x , SO_x and particulate matter, particularly hazardous to human health.

Fuel cells consume hydrogen

Hydrogen can be extracted from water or any carbonaceous fuel

Fossil fuel reforming methods are being developed which will enable the employment of fuel cells ahead of the installation of a hydrogen infrastructure

The second stage, involving the direct extraction of hydrogen from water, will only come when the storage and transportation problems as well as the capital and operating-cost problems have been surmounted. Such an economy would be free of pollutants along the entire energy chain, but for the present, remains a long-term goal. In the meantime, as noted above, reforming technologies to enable fuel cells to make full use of the existing refuelling infrastructures are being developed.

The second stage, involving the direct extraction of hydrogen from water, will only come when the storage and transportation problems as well as the capital and operating-cost problems have been surmounted

Fuel cell use

Fuel cells currently being developed will be able to cover power requirements ranging from milliwatts, for consumer electronics to multi-megawatts capable of supplying industrial parks. This can be broken down into four major subgroups:

Table 8: Potential fuel cell applications

Subgroup	Power range	Application area
1. Portable Power	milliwatts to 1kW	Consumer/military electronics
2. Compact Power	1 to low double-digit kW	Compressors, Concrete mixes
3. Stationary Power	low single-digit kW to multi-MW	Housing to industrial plant
4. Automotive Power	Low single to triple-digit kW	Bikes, cars, trucks

Source: UBS

1. **Portable Power.** The fuel cells that will ultimately power consumer and military electronic devices such as laptop computers and personal mobile communicators look set to draw the hydrogen from a water/methanol mix. These devices will use the so-called direct methanol fuel cell, employing fountain pen-type methanol cartridges to power the devices. Given the wide acceptance of methanol to clean auto window screens and the size of the refill cartridges, infrastructure in this market hardly presents a problem. The source of most methanol production is natural gas.
2. **Compact Power.** Devices requiring low double-digit kilowatts of power, such as concrete mixes and compressors, will use a reformer to strip the hydrogen from bottled gas like propane. Given the extensive use of this fuel in the camping and leisure markets, infrastructure would seem to pose few problems.
3. **Stationary Power.** Non-centralised power for homes, commercial buildings and industrial plant will no doubt make full use of the existing natural gas pipeline infrastructure. The most likely outcome at present is that such devices will use a fuel processor to strip the gas of its hydrogen and feed this 'reformat' into the fuel cell stack.
4. **Automotive Power.** Captured fleets, such as those operating at airports or defined cycle vehicles such as city buses or postal vehicles, could easily use electrolysed hydrogen given the predictability of their working cycles and the fact that they operate out of centralised depots. But this is far from the case with passenger vehicles or haulage fleets. Bluntly put, a hydrogen infrastructure will not be developed without the agreement and co-operation of the oil companies. And the oil companies will not allow their assets to be so easily stranded.

Most automobiles will employ on-board reformers, converting carbonaceous fuels pumped from the existing refuelling infrastructure, to provide the fuel cells with the necessary hydrogen-rich gas streams.

Appendix 1

Important dates in the history of the oil industry

- 1859** First oil well drilled at Titusville, Pennsylvania.
- 1865** John D Rockefeller buys out his partner in one of Pennsylvania's most successful refinery businesses for US\$72,500, and in 1870 forms the Standard Oil Company. By 1881, Standard controlled over 80% of the US oil industry and was responsible for over a quarter of US crude oil production.
- 1871-2** First oil wells drilled in Baku by the Nobel brothers, in what is now Azerbaijan: the beginnings of the Soviet oil industry.
- 1886** Burmah Oil founded by Scottish merchants, headquartered in Glasgow. First operations were oil production and refining in Burma (Myanmar).
- 1891** Marcus Samuel, head of a successful family trading company based in the East End of London, signs a deal with the Rothschilds and the Nobels, who controlled the Russian oil industry, giving him the sole right to transport Baku kerosene eastwards through the Suez canal. The first ships were all named after seashells, in recognition of Marcus's father, who started in business as a shell merchant. On 18 October 1897, the 'Shell' Transport and Trading Company came into existence.
- 1885** Aeilko Jns Zijlker of the East Sumatra Tobacco Company, discovers oil in Sumatra leading, in 1890, to the launching of the Royal Dutch Company. Zijkler dies shortly afterwards and the reins are handed to Jean Baptiste August Kessler, who died in 1900, in turn succeeded by Henri Deterding. By this time, Shell and Royal Dutch together controlled over half of Russian and Far Eastern oil exports.
- 1907** After years of negotiation, Shell and the Royal Dutch Company were combined in the ratio 60:40. Both became holding companies with RD holding 60% of the stock in the operating companies and Shell 40%. There was no Group Board as such, but a Committee of Managing Directors composed of the active members of the Boards of both companies.
- 1901** Oil found in Mexico.
- 1908** Oil discovered in Persia (Iran) by Burmah Oil.
- 1909** The newly founded Anglo-Persian Oil Company went public, with Burmah Oil taking the majority of the shares. By 1912, the company was in financial difficulties.

- 1914** The British government, led by Churchill and driven by the rapid expansion of oil powered battleships, acquired 51% of Anglo-Persian for £2.2m in order to secure fuel supplies for the Admiralty.
- 1911** The US Supreme Court orders the dissolution of the Standard Oil Trust under the 1890 Sherman Anti-Trust Act. Seven new entities are formed in its place: Standard Oil of New Jersey (eventually Exxon), Standard Oil of New York (Mobil), Standard Oil of California (Chevron), Standard Oil of Ohio (eventually the US arm of BP), Standard Oil of Indiana (Amoco), Continental Oil (Conoco) and Atlantic, which became part of Atlantic Richfield Company (ARCO).
- 1913** Oil found in Venezuela.
- 1922** The Neutral Zone delineated by the British between Saudi Arabia and Kuwait, to accommodate the nomadic Bedouin people.
- 1927** Oil found in Iraq.
- 1938** Oil found in Kuwait and Saudi Arabia.
- 1948** Standard Oil of New Jersey (Exxon) joins Socony-Vacuum (Mobil) and Standard Oil of California (Chevron) and Texaco in ARAMCO to exploit the Saudi Arabian oil reserves.
- 1951** Anglo-Persian nationalised by Mohammed Mossedegh. Subsequent British embargo effectively halts Iranian oil exports. The first post-war oil crisis.
- 1954** Anglo-Persian re-named British Petroleum.
- 1956** The Suez Crisis: Nasser takes control of the Suez Canal from French and British interests, temporarily disrupting supplies. The second post-war oil crisis.
- 1956** Oil discovered in Algeria and Nigeria.
- 1957** BP, keen to reduce its dependence on the Middle East, explores in Alaska together with Sinclair Oil. In 1967, ARCO finds the first oil reserves in Prudhoe Bay.
- 1959** Groningen gas field discovered in the Netherlands.
- 1960** OPEC founded in Baghdad by Saudi Arabia, Iran, Iraq, Venezuela and Kuwait in response to aggressive price cutting by the Soviets and Standard Oil of New Jersey. At the time, the five founding members were the source of over 80% of the world's crude exports. The OPEC members agreed to defend the price of oil,

with each member country agreeing to insist that companies consult them on pricing levels.

- 1965** OPEC transfers its headquarters from Geneva to Vienna.
- 1967** Six Day War – Suez Canal closed. Third post-war oil crisis.
- 1969** Oil discovered in the North Sea.
- 1973** Yom Kippur War, Arab oil embargo: fourth post-war oil crisis. Oil prices rise from US\$2.90/bbl in September to US\$11.65 in December.
- 1974** Burmah Oil declared bankrupt – bailed out by British government who paid £178m for Burmah's 25% stake in BP.
- 1979** Iranian revolution. Oil prices surge to more than US\$35/bbl.
- 1979** Shah of Iran goes into exile: Ayatollah Khomeini takes power. Iranian exports cease.
- 1979/81** Oil price rises from US\$13 to US\$34/bbl : fifth post-war oil crisis.
- 1982** OPEC sets first quotas. In 1982, OPEC, which had been producing 31m barrels per day in 1979, set an output limit for the group of 18m barrels per day with an output quota for each country with the exception of Saudi Arabia, which would adjust its production to support the system.
- 1983** OPEC cuts prices by 15% to US\$29/bbl in the face of rising global production, particularly from the North Sea.
- 1986** OPEC introduces 'netback pricing' to gain market share. These deals give refiner buyers a guaranteed return, so sellers resort to them in order to push volume into a weak market. OPEC manages to increase production, but the price of oil collapses and oil revenues plummet.
- 1990** Iraq invades Kuwait; OPEC countries increase production to help stabilise shortfall.
- 1990-91** Gulf War. Sixth post-war oil crisis.
- 1997** OPEC increases production by 10% at OPEC conference in Jakarta.
- 1998** Asian economic downturn and mild winter contribute to rising inventories; the price of oil drops to US\$10/bbl. OPEC agrees production cuts in March and June. Non-OPEC Mexico attends

OPEC conference for first time in March. Attends again in June, joined by representatives from the Russian Federation and Oman.

- 1998** A trend of consolidation and mega-mergers among the largest integrated oil companies began with BP's merger with Amoco. Others soon follow suit including: Exxon Mobil (1999), TotalFinaElf (1999), Repsol YPF (1999), BP Arco (2000), Chevron Texaco (2001), ConocoPhillips (2002).
- 1999** OPEC agrees further cuts in March. Price for Brent blend rises to above US\$20/bbl, from single digits in February.
- 2000** OPEC increases quotas four times in April, July, September and October in response to prices spiking over US\$30/bbl.
- 2001** OPEC cuts quotas four times in response to weak global demand. Additionally, jet fuel demand plummeted in response to the September 11 attacks on the World Trade Centre causing a demand-led oil price slump.
- 2002** US inventories were run down as Venezuelan strikes reduced US imports. US inventories are yet to recover to pre-2002 levels.
- 2003** The crude price fell in anticipation of a quick resolution to the second Iraq war and hopes of Iraqi oil free to trade on world markets in the post-Saddam era.
- 2004** Brent consistently trades over US\$50 as supply disruptions (Hurricane Ivan, Nigerian strikes), and production capacity constraints limit supply at a time of growing global demand, particularly from China.

Appendix 2

Conversion factors

FROM	TO					
Crude oil	Tonnes	Long tons	Barrels	Gallons (Imperial)	Gallons (US)	Tonnes/year
MULTIPLY BY						
Tonnes (metric)	1	0.984	7.33	256	308	-
Long tons	1.016	1	7.45	261	313	-
Barrels	0.136	0.134	1	35	42	-
Gallons (imperial)	0.00391	0.00383	0.0286	1	1.201	-
Gallons (US)	0.00325	0.00319	0.0238	0.833	1	-
Barrels/day	-	-	-	-	-	49.8

TO CONVERT				
Products	Barrels to tonnes	Tonnes to Barrels	Barrels/day to tonnes/year	Tonnes/year To barrels/day
MULTIPLY BY				
Motor Spirit	0.118	8.45	43.3	0.0232
Kerosine	0.128	7.80	46.8	0.0214
Gas oil/diesel	0.133	7.50	48.7	0.0205
Fuel oil	0.149	6.70	54.5	0.0184

TO						
Natural gas and LNG	Billion cubic metres NG	Billion cubic feet NG	Million tonnes crude oil	Million tonnes LNG	Trillion British thermal units	Million barrels of oil equivalent
MULTIPLY BY						
1 billion cubic metres NG	1	35.3	0.90	0.73	36	6.29
1 billion cubic feet NG	0.028	1	0.026	0.021	1.03	0.18
1 million tonnes crude oil	1.111	39.2	1	0.805	40.4	7.33
1 million tonnes LNG	1.38	48.7	1.23	1	52.0	8.68
1 trillion British thermal units	0.028	0.98	0.025	0.02	1	0.17
1 million barrels oil equivalent	0.16	5.61	0.14	0.12	5.8	1

Units

1 metric tonne = 2,205lbs

1 kilolitre (m³) = 6.29bbls

1 therm = 100,000 BTU = 100ft³

Calorific equivalents

One million tonnes of oil equals approximately

Heat Units 40 x 10¹² BTU

397 x 10⁶ therms

10,000 Teracalories

Solid fuels 1.5 x 10⁶ tonnes of coal

3.0 x 10⁶ tonnes of lignite

Electricity 12 x 10⁹ kWh

One million tonnes of oil produces about 4 x 10⁹ kWh of electricity in a modern power station. Calorific values of coal and lignite, as produced

1 cubic metre = 9,000 kcal

1 kWh = 3,412 Btu; 1 kWh = 860 kcal

Appendix 3

Glossary of terms

Here we list some of the more important terms used in drilling and petroleum geology.

Abandon: to cease work on a well which is non-productive/uneconomic.

Acidisation: a process whereby acid is squeezed into tight and/or damaged (usually limestone/chalk) reservoirs, in an attempt to dissolve a portion of the rock, and to improve the porosity and permeability characteristics of the reservoir, thereby improving the flow of hydrocarbons to the well.

ACQ: Annual Contract Quantity, which specifies the contracted level of annual gas deliveries.

Acreage: the area over which a company has hydrocarbon exploration interests.

Acrylonitrile: a colourless liquid that is flammable and explosive; used in acrylic fibres, ABS, nitrile rubber.

Annex B: operator's development plan for an installation. It requires government approval before it can be implemented.

Annulus: the space between the drill string and the well wall, or between casing strings, or between the casing and the production tubing.

Anti-clinal traps: essentially formed as a result of a folding of the strata into the shape of a dome, enabling any gas or oil contained in a reservoir rock to collect at the crest of the fold.

API gravity: is specific gravity at 60 degrees Fahrenheit. The higher the API, the lighter the oil.

Appraisal well: a well drilled to determine the physical extent, reserves and likely production rate of a field, to assess the commerciality of the discovery.

Aromatics: a group of unsaturated cyclic hydrocarbons containing one or more structural carbon rings. They are highly reactive and chemically versatile. The group name is derived from the strong and not unpleasant odour characteristic of most chemicals in this family.

Associated gas: natural gas associated with accumulations of oil, which may be dissolved in the oil or may form a cap of free gas above the oil.

Barrel: a unit of volume measurement used for petroleum and its products (7.33 barrels = 1 ton; 6.29 barrels = 1 cubic metre).

bbl: one barrel of oil. 1 barrel = 35 imperial gallons (approx.), or 159 litres (approx).

bcf: billion cubic feet. 1 bcf = 0.83 million tonnes of oil equivalent.

bcm: billion cubic metres (1 cubic metre = 35.31 cubic feet).

Bed: the geological term defining a stratum of any thickness, and of uniform homogeneous texture.

Boe: barrels of oil equivalent (see Conversion Factors section)

Benzene: a liquid that is flammable and explosive, used to make ethylbenzene, phenol, cyclohexane (for nylon), and detergents.

Bit: a sophisticated cutting tool utilised in drilling. Two types are currently used – rock bits (roller cone) and diamond bits. Roller cone bits are most common and high-performance diamond bits are selected when their extended work life is important. They are most noticeable in deep wells and where operating costs are high.

Bitumen: the black/brown sludge or solid that is used to produce asphalt. Although it can occur naturally, bitumen also results from the distillation process.

Block: an acreage sub-division approximately 10 x 20 kms, forming part of a quadrant. For example, Block 9/13 is the 13th block in Quadrant 9.

Blow-down: condensate and gas is produced simultaneously from the outset of production.

Blow-out preventer: high-pressure wellhead valve, designed to shut off the uncontrolled flow of hydrocarbons.

Blow-out: occurs when well pressure exceeds the ability of the wellhead valves to control it, resulting in uncontrolled hydrocarbon flow.

Borehole: the hole as drilled by the drill bit.

Bottom-hole assembly (BHA): Lower part of drill-string from the bit to the drill pipe. Can consist of drill collars, subs such as stabilizers, reamers, and jars, mud motors, MWD, bit sub and bit.

Cantilever jack-up: Type of offshore rig jacked up on self-elevating legs using a rack and pinion system. A cantilever jack-up enables the drilling package to move to the extent that it can be cantilevered over the side of the rig and extend over an existing platform. Provides increased drilling and work-over flexibility.

Cap rock: an impervious layer, eg clay, overlying a reservoir rock and preventing the petroleum from escaping upwards.

Carbonate rock: a sedimentary rock, sometimes a reservoir rock primarily composed of calcium carbonate (limestone, chalk) or calcium magnesium carbonate (dolomite); it sometimes forms petroleum reservoirs.

Casing: the steel lining that supports the sides of the well and prevents the flow of fluid both from and into the well bore. In addition, it provides a means of controlling well pressures and oil production.

Casing perforation: in cased wells, the casing is pierced in the hydrocarbon-bearing formation in order to allow the hydrocarbon to flow into the well. This operation is performed by a perforating gun made up of a number of linked-shaped explosive charges.

Catalyst: a substance that enables a chemical reaction to take place at a faster rate or under different conditions, such as a lower temperature than otherwise possible.

Catalytic cracking: whereas distillation separates a liquid (or solid) into its constituent parts, but does not change them, catalytic cracking alters the molecular structure of the constituent parts.

Catalytic reformation: the use of a catalyst to effect the rearrangement of certain hydrocarbon molecules without altering their composition appreciably; the conversion of low-octane gasoline fractions into higher-octane fractions.

Cement/cementing: the filling of the space between the casing and the borehole wall with cement. This keeps the casing in the hole stationary and prevents leakage to or from other strata that have been drilled through.

Cetane number: a measure of diesel fuel's propensity for self-ignition. The higher the cetane number, the greater the combustibility (more desirable) of the diesel fuel.

Choke: a steel orifice contained within a Christmas tree to regulate the flow of hydrocarbons from the well to the manifold or production separator, or to regulate the flow of water or gas in injection wells.

Christmas tree: the assembly of fittings and valves on the top of the casing that controls the production rate of oil.

CIF: Cost, Insurance and Freight. The seller must pay the cost, freight and insurance necessary to bring the oil/LNG to the named destination.

Clastic rocks: sedimentary rocks composed of fragments of pre-existing rocks.

CNS: Central North Sea.

Coflexip: French pipeline company. The name is also being used increasingly as a generic name for composite flexible pipelines.

Commercial field: hydrocarbon field judged to be capable of producing enough net income to make it worth developing.

Completion: A single operation involving the installation of equipment in and on a well, after drilling and evaluating the well, to bring on production from one or more zones.

Condensate: hydrocarbons which are gaseous under reservoir conditions and which become liquid when temperature or pressure is reduced. A mixture of pentanes and higher hydrocarbons.

Coring: taking rock samples from a well by means of a special tool – a ‘core barrel’.

Crane barge: a large barge, capable of lifting heavy equipment onto offshore platforms. Usually known as a ‘derrick barge’.

Creaming Theory: a statistical technique which recognises that in any exploration province after an initial period in which the largest fields are found, success rates and average field sizes decline as more exploration wells are drilled and knowledge of the area matures.

Coke: the residue of coal left after catalytic cracking of oil that is used as fuel.

Condensates: are liquid hydrocarbons recovered from non-associated gas reservoirs. They are composed of C4 (butane, etc...) and higher carbon number hydrocarbons. They normally have an API of between 50° and 85°.

Core: a cylindrical rock sample cut from the well during drilling by means of an annular cutter. These samples are examined to obtain geological information.

Cracked gas: gas which forms as a by-product of the cracking processes. Can be used as an input in the production of chemicals.

Cracking: the refining process of breaking down the larger, heavier, lower-value and more complex hydrocarbon molecules into simpler, lighter, and higher-value molecules. (For example, the process used to transform lower-value crude oil into a higher-value crude oil such as gasoline.) Cracking is accomplished by the application of heat and pressure and, in certain advanced techniques, by use of a catalyst.

Crude assay: a procedure for determining the general distillation and quality characteristics of crude oil.

Cryogenic: of or relating to the production of very low temperatures.

Cubic foot: a standard unit used to measure quantity gas (at atmospheric pressure); 1 cubic foot = 0.0283 cubic metres.

Cuttings: rock chippings cut from the formation by the drill bit, and brought to the surface with the mud. Used by geologists to obtain formation data.

DCQ (Daily Contract Quantity): specifies the contracted level of daily gas deliveries.

Dealer Tank Wagon Price: price paid by retail dealer for delivered branded gasoline.

Dehydrogenation: process by which hydrogen is removed from compounds by chemical means.

Depositional environment: the conditions under which a series of rock strata were laid down. Depositional environments are divided into essentially six groups: marine (laid down under oceans or seas), lagoonal (laid down under sheltered, near-shore marine conditions), deltaic (laid down by a river at its delta), alluvial/fluvial (laid down by a river), lacustrine (laid down under a lake), and aeolian (laid down by wind).

Derrick barge: a sea-going barge fitted with a larger crane(s) capable of lifting objects of up to 14,000 tonnes, eg jacket installation/positioning.

Deviated wells: These are directionally drilled, primarily to allow as large an area as possible to be drained of hydrocarbons from a single location.

Derrick: the tower-like structure that houses most of the drilling controls.

Development well: well drilled to bring a proven oil or gas field into production.

Dew Point: the temperature and pressure at which a liquid begins to condense out of a gas. For example, if a constant pressure is held on a certain volume of gas but the temperature is reduced, a point is reached at which droplets of liquid condense out of the gas. That point is the dew point of the gas at that pressure. Similarly, if a constant temperature is maintained on a volume of gas but the pressure is increased, the point at which liquid begins to condense out is the dew point at that temperature.

Diesel fuel: a general term covering the oils used to make up fuel for diesel engines.

Directional drilling: Intentionally drilling a well at an angle from vertical. Used in offshore wells, for sidetracking a well. Technology that evolved into capability to drill horizontal wells.

Distillation: process via which the various components of the mixture to be distilled can be separated off (fractionated) by the difference in relative boiling points. With reference to the distillation of crude oil it is usually referred to as topping. To prevent the cracking of less volatile distillates (those with a higher boiling point) distillation can be carried out under vacuum.

Drill bit: Cutting tool used in drilling. Most common types are the: (1) roller cone bit; (2) the diamond bit; and (3) the polycrystalline diamond compact bit (PDC). Roller cone bits have rotating cones mounted on legs that are welded to the shank. The legs hold bearings around which the cones spin. Roller cone bits are either milled tooth - steel teeth or tungsten carbide insert (TCI) button bits. Rotary bits can also be drag bits, which have blades that tear into soft formations. Diamond bits are drag bits with no moving parts that have diamonds embedded into the bit. They are used in hard formations and for coring. PDC bits are also drag bits that use man-made diamonds and are good for directional drilling. Regular rotary bits have an opening in the bit body and nozzles between cones or on the face through which drilling fluid flows.

Drilling fluid (mud): Fluid circulated down the well during rotary drilling to: (1) cool and lubricate the bit; and (2) remove well cuttings. Drilling mud is also used to control sub-surface fluids and pressures and provide support to well walls by building a filter cake. Three types: (1) water-base muds; (2) oil-based muds; and (3) gas. Variations can depend on the salinity of the water used from fresh to brines. Additives to muds are clays such as bentonite.

Drilling rig: any kind of drilling unit: land, platform, submersible, semi-submersible jack-up or drill ship. Also means the derrick and its associated machinery.

Drill ship: a ship-shaped drilling vessel that operates in great water depths. The ships are kept in position while drilling by dynamic positioning, a complex system of propellers, thrusters, etc. which are linked to a satellite computer.

Drill Stem Test (DST): this is a procedure whereby the well is alternately flowed and shut-in for varying periods in order to allow the bottom hole pressure to be monitored and the reservoir's response analysed.

Drill string (drill pipe): this is made up of lengths of steel pipe (usually each of 30 feet) connecting the drill bit with the drilling rig. The drill string is utilised to rotate the drill bit and to act as a conduit to circulate drilling mud to the cutting face.

Dry gas: natural gas composed mainly of methane with only minor amounts of ethane, propane and butane and little or no heavier hydrocarbons in the gasoline range.

Dry hole: a well that has proved to be non-productive.

E&A: abbreviation for exploration and appraisal.

E&P: abbreviation for exploration and production.

Effective permeability: the permeability of a rock to fluid when the saturation of the fluid is less than 100%.

Enhanced oil recovery (EOR): any process whereby oil is produced other than by natural reservoir pressure.

Ethane: part of the methane series, this forms one of the main components of naturally occurring gas.

Ethylene: a colourless gas with a slightly sweet odour. It turns from liquid to gas at -155°F . It is flammable and explosive, and is used to produce petrochemical products such as PE, SM, EG, MEG EDC, PVC.

Exploration: the search for oil or gas using detailed geological and geophysical processes followed up, where appropriate, by exploratory drilling.

Exploration well: drilled in areas not already proven to have reserves, to find the limits of a reservoir, or to find new reservoirs in fields where reserves are known to exist. Also known as a 'wildcat well'.

Farm in: when a company acquires an interest in a block by taking over all or part of the financial commitment for drilling an exploration well.

Fault: a fracture along which the rocks on one side are displaced relative to those on the other.

Fault traps: these are caused when a reservoir layer such as sandstone is faulted and juxtaposed against an impervious rock, which prevents the migration of hydrocarbons. Consequently oil or gas accumulates against the fault.

Feedstock: raw material supplied to a machine or processing plant. Here it refers to materials such as natural gas and petroleum used to make petrochemicals.

Field: a geographical area under which an oil or gas reservoir lies.

Fishing: retrieving objects from the borehole, such as a broken drill string or tools.

Fixed cutter bits: See *drill bits (diamond and PDC)*.

Flare: a vent for burning off petroleum products, which cannot be produced or re-injected into the reservoir.

Flexible flow lines: pipelines that are transported to the installation site on reels and uncoiled and laid simultaneously.

Flow rate: the rate at which the hydrocarbons flow up through the oil well, expressed in terms of bbls/day for oil and standard cubic feet per day for gas.

Fluidised catalytic cracking (FCC): a cracking process in which the catalyst is kept in a liquefied form, allowing it to flow back and forth from the regenerator where the coke is burned off, thereby regenerating the catalyst.

F.O.B.: Free on board. The transfer of ownership of crude oil/LNG from the seller to the buyer when the oil/LNG is loaded on board a transportation vessel, as specified in the sales contract.

FPS(O): Floating production system, or floating production, storage and offloading.

Formation fracturing or frac job: a well stimulation process in which frac fluids are pumped down casing or a temporary work string under high pressures to artificially fracture a reservoir rock so as to increase permeability and production. Frac fluid is usually water (sometimes with acid) or diesel oil and can carry thickening agents to increase viscosity or proppants such as sand or aluminium oxide pellets that are suspended in the fluid and are used to hold the fractures open after pumping is complete.

Fraction: that part of petroleum separated off from other parts at a particular boiling range.

Fractionating column: a vertical cylindrical vessel in which oil is distilled, ie, broken down into its constituent parts.

Gas cap: this is a free-gas phase overlying an oil zone and occurring within the same reservoir as the oil.

Gas lift: the process in which productivity rates from a well are increased by injecting gas into the production tubing. The gas, injected deep in the well, mixes with the oil, reduces its density and viscosity, increases the pressure and hence improves the flow rate. The gas can be recovered and re-injected. If the oil in the reservoir has a high associated gas content, this will have a similar effect (and is referred to as a natural gas lift as opposed to artificial gas lift).

Gas field: a field containing natural gas but no oil.

Gas/oil contact (G.O.C.): the interface between the gas cap on a reservoir and the underlying oil column in the reservoir.

Gas/oil ratio (G.O.R.): the volume of gas at atmospheric pressure produced per unit of oil produced.

Gas injection: the process whereby separated associated gas is pumped back into a reservoir for conservation purposes or to maintain the reservoir pressure.

Gasoline: a light petroleum product; also known as petrol.

Geophone: an instrument that detects seismic waves passing through the earth's crust, used in conjunction with seismography.

Gravel packing: the installation of artificial gravel between the production tubing and the well bore in the reservoir. The gravel prevents the collapse of the

well bore and the production of fine sediments that can block or erode the production equipment.

Gravity platform: generally constructed of reinforced concrete, and its design often incorporates a large storage chamber in its base. This chamber may be flooded with water when the platform is on its proposed location, allowing the platform to sink to the sea bed and remain there under its own weight. When oil is being produced, the water contained in the chamber may be replaced by oil for storage purposes.

Heavy crude oil: a crude oil of relatively low API gravity. In the North Sea, oils with an API° of 20 or lower are considered as heavy crudes.

High pressure high temperature (HPHT): a well with a closed-in well head pressure in excess of 10,000 psi and a bottom hole temperature in excess of 150°C.

Horizon: a plane or level of rock stratification assumed to have been once horizontal and continuous: a stratum or set of strata characterised by a particular fossil or group of fossils.

Hydrocarbon: an organic compound consisting only of the elements carbon and hydrogen, derived largely from petroleum, coal tar, and vegetable sources.

Hydrocracking: a cracking process in which heavy hydrocarbons are broken down using a catalyst under high pressure.

Hydrogenation: chemical combination of hydrogen with another substance, usually an unsaturated organic compound, by means of heat, pressure, and catalysts.

Hydrogen skimming: a topper refinery with reformer.

Hydrosulphurisation: used to clean products or inputs by reducing the sulphur content. This is done using hydrogen under pressure over a catalyst. The process is becoming increasingly important, as new environmental legislation requires low sulphur content to improve air quality. Also referred to as hydro-treating.

Improved Oil Recovery (IOR): techniques that result in an increased oil recovery factor from a reservoir compared with previous flow rates. May be achieved by using conventional methods including improved reservoir management and cost-reducing measures, or by using advanced methods (see EOR). Conventional methods include injection of water and/or gas, infill drilling, horizontal wells for drainage of thin oil zones or remaining oil pockets, long-reach wells for drainage of oil in the outer flanks of the reservoir, reduced wellhead pressure or artificial lift in the wells, upgrading of treatment capacity for produced water and/or gas, change of completion strategy.

Injection well: a well used for pumping water or gas into the reservoir.

Inorganic chemical: any chemical compound that does not contain carbon.

Intelligent completion systems: A down-hole completion system that uses sensors and communication equipment to monitor down-hole conditions in real-time. The system's production equipment can also be controlled from the surface to adjust to changing production conditions and maximize hydrocarbon recovery.

Jacket: the lower section, or 'legs', of an offshore platform.

Jack-up rigs: drilling vessels with three or more extendible legs, which are jacked down to the sea bed when a drilling location is reached. The hull must be lifted clear of the water, consequently few rigs of this type can operate in water depths of more than about 90 metres (350 feet). A jack-up rig is equipped with a drilling derrick which projects out away from the hull, enabling the rigs to be utilised to undertake drilling operations from wellhead platforms.

Kerosene: a petroleum product defined by a particular boiling range. Used as lamp oil and jet fuel. Part of the light distillate group.

Lay barge: a barge specially equipped to lay rigid and flexible submarine pipelines.

Light crude oil: a crude oil of relatively high API gravity (usually 35° or higher).

Liquefied natural gas (LNG): as the name suggests, this is simply naturally occurring gas liquefied at certain temperatures and pressures to facilitate storage, transport and handling.

Liquefied petroleum gas (LPG): propane and butanes liquefied under relatively low pressure and ambient temperatures. LPG is a gaseous fuel, about 95% propane. It is stored under pressure at the refinery, sold in pressure cylinders as the familiar bottled gas for domestic use or industrial use where other fuels are less appropriate.

Load factor: mathematical term to express fluctuations in gas demand which is calculated as:

$$\frac{\text{average daily demand}}{\text{peak daily demand}}$$

Logs: see *wireline logs*.

Logging-while-drilling (LWD): using measurement-while-drilling tools to acquire down-hole information in real-time or on a recorded basis. Key measurements include resistivity, porosity, density, and sonics.

Lower 48: the mainland states of the United States, excluding Alaska.

MD (measured depth): the linear distance of a well measured along its drilled projection.

Mboe: million barrels oil equivalent.

Measurement while drilling (MWD): A method and tool used to record or transmit information in real time about well direction and/or formation evaluation during the drilling of the well. The tool is installed in non-magnetic drill collars, as close to the bit as possible. Power is obtained either from turbine generation from drilling mud circulating through the tool, or from batteries. The data can be transmitted to the surface using: (1) fluid pulse, telemetry (2) wireline run in the drill string or by storing it down-hole and retrieving it after each bit run. The pulses are detected by a surface pressure transducer and decoded by computer.

Methane: the main constituent of naturally occurring gas.

Middle Distillate: kerosene, and all gasoils.

Mmcfd: millions of cubic feet per day (of gas).

Modules: an assembly containing numerous components, designed to be installed and disconnected as one. Utilising modules can significantly reduce installation and commissioning times.

Mogas: motor gasoline.

Mt: million tonnes.

Mud: a mixture of base substance and additives used to lubricate the drill bit, bring cuttings to the surface and to counteract the natural pressure of the formation by lining the borehole.

Mud logging: this is the recording of information derived from examination and analysis of formation cuttings made by the bit and mud circulated out of the hole. A portion of the mud is diverted through a gas-detecting device and examined under ultraviolet light to detect the presence of oil or gas.

Multi-client survey: A seismic survey that is conducted and owned by the seismic services company for its own library. The costs of such surveys may be partially underwritten by oil company clients or by the service company themselves. These surveys are typically recorded in areas where multiple clients have widespread access to acreage and can be sold to several customers at a time.

Naphtha: generic term applied to refined, partly refined, or unrefined petroleum products and liquid products of natural gas that boil between 347 and 464°Fahrenheit.

Natural gas: gas, occurring naturally, and often found in association with crude petroleum.

Natural Gas Liquids (NGLs): liquid hydrocarbons found in association with natural gas.

Neutral Zone: the territory between Saudi Arabia and Kuwait where production is shared 50/50 and is included within each countries' respective OPEC quotas.

Naphtha: the gasoline fractions arising from the straight-run distillation of crude. Used as a feedstock for catalytic reforming and for chemicals manufacture.

Octane: the level of gasoline's resistance to pre-ignition. High-compression engines can induce early ignition in lower octane fuels during the compression stroke resulting in engine locking.

Oil: a mixture of liquid hydrocarbons of different molecular weights.

Oil field: a geographic area under which an oil reservoir lies.

Oil in place (OIP): an estimated measure of the total amount of oil contained in a reservoir, and, as such, a higher figure than the estimated recoverable reserves of oil.

Oil water contact (OWC): the interface between the oil in a reservoir, and the underlying water.

Olefins: a class of unsaturated aliphatic hydrocarbons with the general formula of one carbon for every two hydrogens. They are the 'ene' form of paraffins (ie, ethylene is the olefin of the paraffin ethane). The 'ene' suffix means that the polymer contains one or more double bonds, and is chemically reactive.

Operator: the company that has legal authority to drill wells and undertake production of the hydrocarbons found. The operator is often part of a consortium and acts on behalf of this consortium.

Organic chemical: any chemical that contains carbon.

Packer: an expandable device that is run in either an open well, cased hole or in tubing to prevent fluids from flowing vertically. Consists of a sealing element, a holding or setting device, and a fluid passage. Often used to isolate zones for well testing, for cement and acid jobs or to complete a well. Can be reusable or permanent, depending on the application.

Paraffins: class of aliphatic hydrocarbons characterised by a straight carbon chain and having the generic formula C_nH_{2n+2} ; also called alkanes; occur primarily in Pennsylvania and mid-continent in the US.

Pay sand: the producing formation, often one that is not actually sandstone. It is also called pay, pay zone, and producing zone.

Pay zone: rock in which oil and gas are found in exploitable quantities.

Perforate: to pierce the casing wall and cement to provide holes (perforations) through which formation fluids may enter the well-bore, or to provide holes in the casing so that materials may be introduced into the annulus between the casing and the wall of the bore hole. Perforating is accomplished by lowering into the well a perforating gun that fires electrically detonated bullets or shaped charges radially through the casing.

Permeability: the measure of the ability of the reservoir rock to allow the hydrocarbons to flow – measured in milli-Darceys (mD).

Petrochemical: any organic chemical for which petroleum or natural gas is the ultimate raw ingredient.

Petroleum: a generic name for hydrocarbons, including crude oil, natural gas liquids, natural gas and their products.

Piling: Refers to the steel ‘pins’ which are driven through specially designed slots on a jacket platform on a sub-sea template, and into the sea bed, in order to hold the structure in place. The ‘pins’ are often driven down to a depth of 45 metres (150 feet) or more.

Plastic: a high polymer, usually synthetic, combined with other ingredients, capable of being formed or moulded under heat and pressure, and of being machined to high dimensional accuracy, trimmed, and finished in its hardened state.

Platform: an offshore structure that is permanently fixed to the sea bed.

Play: a hydrocarbon play is a set of circumstances that combine to create the conditions necessary for the accumulation of oil and/or gas. A single play may contain a number of discoveries and prospects, but the favourable combination of the controlling geological parameters usually occurs over a limited geographic area, sometimes referred to as a ‘fairway’.

Plugged: when the bore hole is sealed – either dry, uncommercial or awaiting further assessment.

Polyethylene (PE): a solid, white, wax-like material made by polymerising ethylene, and is a good electrical insulator that can be moulded. Applications include: LD/LLDPE (used in packaging film, toys, water bags, electrical insulation, wire and cable coating), HDPE (a substitute for polystyrene – used in blow-moulded products, injection-moulded items such as piping, fibres, gasoline and oil containers, man-made paper).

Polypropylene (PP): is a commodity thermoplastic resin that is translucent, readily coloured, and maintains its strength after repeated flexing. The primary end markets for PP are film (snack food wrappers), yarn and fibre (carpet backing, rope and upholstery), and moulded parts (auto bumpers and electrical components).

Polystyrene (PS): Transparent, hard solid with high strength and impact resistance. There are four subgroups: GPS (general), EPS (expandable), HPS (high impact) and FRPS (fire resistant). GPS – used to produce containers, toys and plastic boards; HPS – a co-polymer of SM and BR, which may be processed into safety helmets, and auto and electrical parts; EPS – can be used to produce food containers and packaging. Consumer products include PS foam (ie, disposable coffee cups). There is a lot of competition between PS and the other five big thermoplastics: LDPE, LLDPE, HDPE, PP and PVC. PS continues to lose market share, but seems to have a permanent place in some applications, particularly moulded foams (for carry-out food containers, some extrusion, sheet and film applications).

Polyvinyl chloride (PVC): A synthetic thermoplastic polymer that can be decomposed at 148°C, emitting toxic fumes of hydrogen chloride. End uses include piping and conduits of all kinds, electrical insulation, film, raincoats, door frames, magnetic tapes.

Proppant: Small, well sorted grains that are hard and granular or spherical shaped used to hold open fractures created during a frac job. Sand is the most common proppant; ceramic beads are another popular product.

Propylene: a colourless gas that is flammable and explosive; used to make AN, PP, and isopropyl alcohol.

Purified terephthalic acid (PTA): a white crystal or powder; a key ingredient for polyester resins and fibres.

Probable: those reserves which are not yet proven but which are estimated to have a better than 50% chance of being technically and economically viable.

Porosity: the percentage of void in a porous rock compared with the solid formation.

Possible: those reserves that at present cannot be reserves regarded as ‘probable’ but are estimated to have a significant but less than 50% chance of being technically and economically producible.

Primary Migration: the initial displacement of the hydrocarbon from the source rock to the surrounding strata.

Primary recovery: recovery of oil or gas from a reservoir purely by using the natural pressure in the reservoir to force the oil or gas out.

Proven field: an oil and/or gas field whose physical extent and estimated reserves have been determined.

Proven reserves: those reserves, which on the available evidence, are virtually certain to be technically and economically viable (ie, have a better than 90% chance of being produced).

PTD: prognosed or predicted total depth of a well.

RVP: Reid Vapour Pressure. A measure of the surface pressure required to maintain a gaseous material in a liquid state at 60°F. Low RVP gasoline (reduced tendency to vaporise) is used to avoid vapour lock and static emissions in warm climates and at higher altitudes. Higher RVP gasoline is required for cold starts during the winter.

Recoverable: that proportion of the oil and/gas in a reservoir that can be removed using currently available techniques.

Recovery factor: the ratio of recoverable oil and/or gas reserves to the estimated oil and/or gas in place in the reservoir.

Refinery catalytic cracker: facilities in a refinery where petroleum is cracked with the use of a catalyst.

Reforming: the process by which the molecular structure of straight-run gasoline fractions is altered to improve the so-called 'anti-knock' quality. This increases the octane level, which in turn reduces the flash point of a fuel. This allows greater performance from a compression engine, allowing the spark to ignite the fuel, rather than the heat from compression prematurely causing the explosion.

Reforming process: the use of heat and catalysts to effect the rearrangement of certain hydrocarbon molecules without altering their composition appreciably; the conversion of low-octane gasoline fractions into higher-octane stocks suitable for blending into finished gasoline; the conversion of naphtha to obtain more volatile product of higher octane number.

Re-injection: natural gas produced in association with crude oil can be re-injected to maintain reservoir pressure or avoid flaring it.

Residue: the leftover from the refining process. Long residue forms from the atmospheric distillation of crude, and can be distilled under vacuum to produce a heavier residual, called short residue. Cracked residue is that substance left over from thermal cracking operations.

Reservoir: the underground rock formation where oil and gas have accumulated. It consists of a porous and permeable rock holding the oil or gas.

Rig Count: Statistical measure of industry activity that essentially seeks to determine how much drilling, completion and work-over activity is occurring

around the world. There are many different types of rig count, but the Baker Hughes rig count has been the industry standard for many years.

Riser: pipe connecting wells or sub-sea production equipment to the surface.

Rotary steerable system: A tool designed to drill directionally with continuous rotation from the surface, eliminating the need to slide a steerable motor. Tools generally come in two designs – push the bit and point the bit. Push the bit systems use external pads on the side of the tool to push the drill bit in the desired direction. Point the bit systems use an internal rod that rotates in an elliptical fashion to point the drill bit in the desired direction. RSS systems tend to drill faster, smoother, more accurate directional/horizontal well bores than conventional down-hole motors.

Roughneck: drill crew members who work on the derrick floor, screwing together the sections of drill pipe when running, or pulling a drill string.

Roustabout: drill crew members who handle the loading and unloading of equipment and assist in general operations around the rig.

Royalty payment: the cash payment or payment in kind paid to the owner of the mineral rights (often the state).

Sand control: methods for preventing and dealing with loose, unconsolidated sands that drift or wash into the bottom of the well or into the down-hole pumping equipment during petroleum production. A gravel pack, expandable sand screen, and chemical consolidation are examples of sand control.

Sandstone: a detrital, sedimentary rock composed of individual grains of sand (commonly quartz) stuck together by silica, calcium carbonate, iron oxide or other cements. Sandstone is a common rock in which petroleum and gas accumulate.

Secondary migration: long globules of oil are forced through pore spaces in the rock by the force of moving water. Being lighter than water, it is usually forced upwards until it emerges at the surface or is trapped under a cap rock to form an accumulation of oil or gas.

Secondary recovery: recovery of oil or gas from a reservoir by artificially maintaining or enhancing the reservoir pressure by injecting gas, water or other substances into the reservoir rock.

Sedimentary rocks: formed by the compaction of mineral grains, which have been laid down as a result of denudation of land surfaces by water, ice, wind and sea. They often contain some amount of organic matter, the source material for oil and gas. Some sedimentary rocks have suitable properties of porosity and permeability.

Seismic survey: a technique to obtain geophysical data by projecting pressure waves from the sea through the sea-bed and into the rocks.

Semi-submersible rig: a floating platform moored on location by anchors on the sea-bed and/or with a dynamic positioning system of computer controlled thrusters. Stability in the water is achieved by submerged pontoons. Suitable for deep water, hostile sea environments, and development drilling in particular.

Separators: processing equipment that splits the well-head fluid into separate oil, water and gas streams.

Shale oil: oil extracted by heat from clays which are impregnated with oil.

Show: an indication of the presence of gas or oil in the formations penetrated during drilling, ie a trace amount of oil or gas.

Sidetracking: is the use of an existing well bore to drill an additional bore laterally.

Source rocks: hydrocarbons originated from organic matter, deposited and preserved within sedimentary rocks. Any sediments that have high organic carbon content and produce hydrocarbons in significant amounts are known as source rocks.

Sour crude/gas: has a high sulphur content in the form of hydrogen sulphide and mercaptans. In the case of sour crude, high commonly means more than 1%.

Spudding: the operation of drilling the first part of a new well.

Spur lines: generally small diameter pipelines connecting a production facility to either a terminal platform or to a main pipeline leading to the shore.

Steam crackers: crackers that use steam heat to initiate the process of breaking down larger, heavier, more complex hydrocarbons into simpler and lighter ones.

Steam reformation: the use of steam heat to effect the rearrangement of certain hydrocarbon molecules without altering their composition appreciably. The process changes the naphthenes in naphtha to aromatics, which increases the aromatics content of the oil from 20% to 50%; the conversion of low-octane gasoline fractions into higher-octane stocks suitable for blending into finished gasoline (an increase in aromatics content increases octane).

Stratigraphic traps: can occur where sedimentary layers have changed in character. For instance, a deposit of coarse sand near the shore may have given place to finer grained sediment in deeper water and, as these sediments will vary in porosity/permeability, an apparently isolated reservoir can occur within this layer. Another case would be where a sand layer wedges out onto an impermeable clay or shale and becomes isolated from its own sedimentary layer. The latter type of trap is sometimes known as a pinch-out trap.

Structural traps: result from some local deformation, such as folding, faulting or both, of the reservoir and cap rock. Typical examples are anti-clinal and fault traps which are sometimes connected with salt domes.

Sub-sea production system: these are essentially wells drilled from a mobile drilling rig and completed with a series of Christmas trees and manifolds on the sea-bed. This well head equipment is then connected to a central collecting area (either a platform, or FPS) by flexible or rigid pipelines.

Suspended well: a well that has been capped off temporarily.

Sweet crude gas: hydrocarbons relatively free from sulphur compounds.

Swing: the fluctuation in gas demand and, as a result, supply during a specific period (day, week year, etc.). The higher the swing, the greater the fluctuation. (see also load factor).

Straight-run: a production resulting from the distillation of petroleum without chemical conversion (ie, no adjustment to the molecular structure or size).

TCF: trillion cubic feet (of gas).

Tertiary recovery: methods of increasing the percentage of oil from oilfields beyond that achieved by secondary recovery. Methods include injecting solvents or high-pressure carbon dioxide, igniting part of the oil in the reservoir to generate steam, and biological breakdown of oils to enable them to flow more freely.

Thermal cracking: the use of heat to reduce the size of hydrocarbon molecular structure to convert heavy oils into lighter, more value added products.

Tight hole: well results that are not disclosed for commercial reasons.

Toluene: aromatic with many uses, including the production of dye stuffs and pharmaceuticals.

Topping: alternative term for crude oil distillation.

Tops: the lightest grade of gasoline, its name being derived from the fact that it is often the product taken from the top of the fractionating column.

Topsides: the superstructure of a platform, contains processing facilities and/or living quarters.

Trap: an arrangement of sedimentary strata which have the ability/potential to hold hydrocarbons, should they have been produced in the vicinity. By definition, the strata will contain a reservoir rock and cap-rock. Traps are commonly combinations of the above types, sometimes termed combination traps.

Treating processes: these are in addition to the standard processes undertaken at a refinery and are used to clean up products in preparation for marketing. An example is the reduction of sulphur content to fulfil quality requirements.

ULCC: ultra-large crude carrier.

Unitisation: occurs when interest holders of petroleum reserves pool their individual interests in return for an interest in the overall unit, which is then operated by one company on behalf of the group. Unitisation should lead to increased efficiency from maximising production and minimising development and production costs.

Vacuum distillation: use of a vacuum to maintain stable temperatures so as to prevent cracking (change in the chemicals make-up of a hydrocarbon).

Vinyl chloride (VCM): compressed gas that is easily liquefied, and usually handled as a liquid. Phenol is added as a polymerisation inhibitor. Used in PVC and copolymers, organic synthesis, adhesives for plastics.

Visbreaking: thermal cracking used to reduce the viscosity (essentially, thickness) of long or short residues (see *Residue* above).

VLCC: very large crude carrier.

Watered-out: when a production well is shut-in due to its unacceptably high proportion of water production.

Water flood: a method of secondary recovery in which water is injected into a reservoir in order to remove additional quantities of oil that would otherwise be left behind after primary recovery.

Water injection: see secondary recovery and water flood.

Well head: See *Christmas tree*.

Well head platform: a minimum-facilities offshore platform utilised to locate well control and production facilities on the surface. No accommodation, processing or drilling facilities are provided. Wells are drilled from the platform with the assistance of a mobile drilling rig.

Wildcat: refers to an exploration well drilled without comprehensive geological knowledge of the locality.

Wireline logs: electrical tools run down a well on a steel cable. The equipment measures rock properties such as gamma radiation, which are used to determine rock properties through petrophysical equations such as lithology, permeability, porosity, formation fluid type, cement bond effectiveness, etc.

Well log: a record of the geological formations penetrated during drilling, including technical details of the operation.

Wildcat well: speculative drilling on unproven acreage. Also known as an 'exploration well'. Etym: The term comes from exploration wells in West Texas

in the 1920s. Wildcats were abundant in the locality, and those unlucky enough to be shot were hung from oil derricks.

Work-over: remedial work to the equipment within a well, the well pipe-work, or relating to attempts to increase the rate of flow.

Yields: the ratio of light products to residue for any given barrel of oil from the same process will be influenced by the specific gravity of oil. For example, lighter crudes such as Brent will yield a greater proportion of lighter products compared with Arab Heavy.

Appendix 4

Company websites

Company	Website	Company	Website	Company	Website
Abbot Group	www.abbotgroup.com	Hindustan Petroleum	www.hpcl.co.in	Quicksilver Resources	www.qrinc.com
Aker Maritime	www.akermaritime.no	Houston Exploration	www.houstonexploration.com	Reliance Industries	www.ril.com
Amerada Hess	www.hess.com	Husky Energy	www.huskyenergy.com	Repsol YPF	www.repsol-ypf.com
Anadarko	www.anadarko.com	IHC Caland	www.ihccaland.com	Rowan Companies	www.rowancompanies.com
Apache	www.apachecorp.com	Imperial Oil	www.imperialoil.com	Royal Dutch / Shell	www.shell.com
Ashland Inc	www.ashland.com	Indian Oil Corp.	www.iocl.com	Saipem	www.saipem.com
BP	www.bp.com	JKX Oil & Gas	www.jkx.co.uk	Santos	www.santos.com
Baker Hughes	www.bakerhughes.com	Kerr McGee	www.kerr-mcgee.com	Sasol	www.sasol.com
Baytex Energy	www.baytex.ab.ca	Kinder Morgan	www.kindermorgan.com	Schlumberger	www.slb.com
BG Group	www.bg-group.com	Louis Dreyfus	www.ldng.com	Shell Canada	www.shell.ca
Bharat Petroleum	www.bharatpetroleum.com	Lukoil	www.lukoil.com	Shell T&T	www.shell.com
BHP	www.bhp.com	Marathon Oil Company	www.marathon.com	Showa Shell Sekiyu	www.showa-shell.co.jp
BJ Services	www.bjservices.com	Medco Energi	www.medcoenergi.com	Sibneft	www.sibneft.com
Bonavista Energy	www.bonavistaenergy.com	Meota Resources	www.meota.com	Singapore Petroleum	www.spc.com.sg
Burlington Resources	www.br-inc.com	Mol	www.mol.hu	Sinopec	www.sinopec.com
Burren Energy	www.burren.co.uk	Murphy Oil	www.murphyoilcorp.com	SK Corporation	www.skcorp.co.kr
Cairn Energy	www.cairnenergy.com	Nabors	www.rigs.com	Smith International	www.smith.com
Cal Dive International	www.caldive.com	Newfield Exploration	www.newfld.com	Soco International	www.socointernational.co.uk
Caltex	www.caltex.com	Nexen Inc	www.nexeninc.com	S-Oil	www.s-oil.co.kr
Canadian Natural Resources	www.canadiannaturalresources.com	Niko Resources	www.nikoresources.com	Spinnaker Exploration	www.spinnakerexploration.com
Canadian Oil Sands	www.cos-trust.com	Nippon Oil	www.eneos.co.jp	Statoil	www.statoil.com
CEPSA	www.cepsa.es	Nippon Mining Holdings	www.jcr.co.jp	Stolt Offshore	www.stoltoffshore.com
Chesapeake Energy	www.chesapeake.com	Noble Affiliates	www.nobleaff.com	Suncor Energy	www.suncor.com
ChevronTexaco	www.chevrontexaco.com	Noble Drilling	www.noblecorp.com	Sunoco	www.sunocoinc.com
China Oilfield Services	www.cnocs.com	Noble Energy Inc.	www.nobleenergyinc.com	Swift Energy	www.swiftenergy.com
Cimarex	www.cimarex.com	Norsk Hydro	www.hydro.com	Surgutneftegaz	www.surgutneftegas.ru
CNOOC	www.cnooc.com	Occidental Petroleum	www.oxy.com	Talisman	www.talisman-energy.com
Co. GL de Geophysique	www.cgg.com	Oil Search	www.oilsearch.com.au	Tatneft	www.tatneftjsc.ru
ConocoPhillips	www.conoco.phillips.com	OMV	www.omv.com	Technip	www.technip-coflexip.com
Cooper Cameron	www.coopercameron.com	ONGC	www.ongcindia.com	Teikoku Oil	www.teikokuoil.co.jp
Cosmo Oil	www.cosmo-oil.co.jp	Origin Energy	www.originenergy.com.au	Tesoro Petroleum	www.tesoropetroleum.com
Dana Petroleum	www.dana-petroleum.com	Paladin Resources	www.paladinresources.plc.uk	TGS NOPEC	www.tgsnopec.no
Devon Energy	www.devonenergy.com	Paramount Resources	www.paramountres.com	Tidewater	www.tdw.com
Diamond Offshore	www.diamondoffshore.com	Patina Oil & Gas	www.patinaoil.com	Tonen General Sekiyu	www.tonengeneral.co.jp
Dragon Oil	www.dragonoil.com	Patterson-UTI Energy	www.patenergy.com	Torch Offshore	www.torchinc.com
EnCana	www.encana.com	Pennwest Petroleum	www.pennwest.com	Total	www.total.com
Eni	www.eni.it	Petrobras	www2.petrobras.com.br	Transocean	www.deepwater.com
Ensco	www.ensco.com	Petrobras Energia	www.petrobrasenergia.com	Trico Marine	www.tricomarine.com
Ensign Resources	www.ensigngroup.com	PetroCanada	www.petro-canada.ca	Tullow Oil	www.tulloil.ie
EOG Resources	www.eogresources.com	PetroChina	www.petrochina.com.cn	Tupras	www.tupras.com.tr
Evergreen Resources	www.evergreen-res.com	PetroKazakhstan	www.petrokazakhstan.com	Ultra Petroleum	www.ultrapetroleum.com
ExxonMobil	www.exxonmobil.com	Petroleum Geo-Services	www.pgs.com	Unocal	www.unocal.com
First Calgary Petroleum	www.fcpl.ca	Pioneer	www.pioneer-mrc.com	Valero	www.valero.com
Forest Oil	www.forestoil.com	Pioneer Natural Res.	www.pioneer-canada.com	Varco International	www.varco.com
Fred Olsen Energy	www.fredolsen-energy.no	Petrobras	www.petrobras.com	Venture Production	www.vpc.co.uk
GAIL (India)	www.gailonline.com	PKN	www.orlen.pl	Vintage Petroleum	www.vintagepetroleum.com
Gazprom	www.gazprom.ru	Plains Exp. & Prod.	www.plainsxp.com	Weatherford	www.weatherford.com
Geophysique	www.cgg.com	Pogo Producing Company	www.pogoproducing.com	Western Gas Res.	www.westerngas.com
Global Industries	www.globalind.com	Precision Drilling	www.precisiondrilling.com	WH Energy Services	www.whes.com
Global Marine	www.glm.com	Premcor	www.premcor.com	Wood Group	www.woodgroup.com
Global SantaFe	www.gsfdriill.com	Premier Oil	www.premieroil.com	Woodside Petroleum	www.woodside.com.au
Grant PrideCo	www.grantprideco.com	Pride International	www.prideinternational.com	XTO Energy	www.xtoenergy.com
Halliburton	www.halliburton.com	Prosafe	www.prosafe.com	Yukos	www.yukos.com
Hardman Resources	www.hdr.com.au	PTTEP	www.ptt-ep.com		
Hellenic Petroleum	www.hellenic-petroleum.gr	PTT Public Co Ltd	www.pttplc.com		

Industry websites

American Petroleum Institute	www.api.org
Baker Hughes Rig Count	www.bakerhughes.com/investor/rig/index.htm
Canadian Association of OilWell Drilling Contractors	www.caodc.ca
Central Intelligence Agency	www.odci.gov/cia/ciahome.html
Department of Commerce	www.doc.gov
DOE	www.eia.doe.gov
International Energy Agency	www.iea.org
International Monetary Fund	www.imf.org
Minerals Management Service	www.mms.gov
NOAA 6-10 US Weather Forecast	www.cpc.ncep.noaa.gov/products/predictions/610day
OECD Washington Centre	www.oecdwash.org
Offshore rigcount and information	www.rigzone.com
OPEC	www.opec.org
Purvin & Gertz	www.purvingertz.com
SEC Edgar Archives	www.sec.gov/cgi-bin/srch-edgar
SEC filings	www.freeedgar.com
Society of Petroleum Engineers	www.spe.org
UK Department of Trade & Energy	www.dti.gov.uk/energy

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The risks associated with our investment thesis include volatility in oil and natural gas prices, margins for global refining, marketing, and chemicals, as well as normal exploration risks associated with the oil and gas business.

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Neutral 1	FSR is between -10% and 10% of the MRA, higher degree of predictability	Neutral 2	FSR is between -10% and 10% of the MRA, lower degree of predictability	Hold/Neutral	50%	33%
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1: Percentage of companies under coverage globally within this rating category.

2: Percentage of companies within this rating category for which investment banking (IB) services were provided within the past 12 months.

Source: UBS; as of 30 September 2004.

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Market Return Assumption (MRA) is defined as the one-year local market interest rate plus 5% (an approximation of the equity risk premium).

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Unless otherwise indicated, please refer to the Valuation and Risk sections within the body of this report.

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